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Full Name of Author — Nom complet de l'auteur

JOHN PHILIP PRINCE

Date of Birth — Date de naissance

APRIL 21, 1944

Country of Birth — Lieu de naissance

CANADA

Permanent Address — Résidence fixe

2225 25 A ST. S.W. CALGARY ALBERTA

Title of Thesis — Titre de la thèse

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Name of Supervisor — Nom du directeur de thèse

DR. W. D. GAINER

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Ⓒ JOHN PHILIP PRINCE

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(Signed) J.P. Prince

PERMANENT ADDRESS:

#205 - 2010 Ulster Road N.W.
Calgary, Alberta T2N 4C2
Canada

DATED June 12, 1980

THE UNIVERSITY OF ALBERTA

FACULTY OF GRADUATE STUDIES AND RESEARCH

The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled The Economic Potential of Enhanced Oil Recovery in Canada

submitted by John Philip Prince

in partial fulfilment of the requirements for the degree of Doctor of Philosophy

W D Gainer
Supervisor

Edward H. Shaffer

J. J. Freeman

A. J. Stock

R S Uhler
External Examiner

Date June 12, 1980

ABSTRACT

This study estimates the aggregate potential for increasing oil recovery from existing reservoirs using methods that go beyond standard primary and secondary (primarily waterflood) recovery methods. These procedures are referred to as 'tertiary' or 'exotic' recovery methods, or more generally as 'Enhanced' oil recovery. Individual reservoirs are checked for technical amenability to enhanced recovery methods by comparing the values of selected reservoir parameters to critical ranges for these parameters that are based on engineering theory and field results. The initial ranges for a number of important parameters comprise a screening procedure that allows only those reservoirs with a reasonable chance of technical success to emerge. The screening procedure used here was developed initially by Lewin and Associates for a 1976 study of enhanced recovery in the United States and has since been adapted to investigate reservoirs in Alberta by the Petroleum Recovery Institute in Calgary.

Reservoirs that appear as technical candidates are evaluated as investment projects by conventional cost-benefit analysis under a number of oil price and development cost scenarios and using several discount rates. The base case analysis assumes standard development and operating costs in 1978 dollars, an assumed domestic wellhead price of oil of $20 per barrel, and a real discount rate of 8 per cent per year.

The 1975 file of Alberta Energy Resources Conservation Board data on reservoirs is screened using the procedures discussed above. The screening procedure eliminates some reservoirs from consideration and

assigns each technically viable reservoir to one or more recovery processes that appear to be feasible for use in that reservoir.

The processes considered are: steam drive, steam stimulation, in situ combustion, polymer augmented waterflood, alkaline flood, microemulsion flood, CO_2 miscible, and hydrocarbon miscible. Recovery models specific to each process are applied to all reservoirs that emerge from the screening procedure to estimate incremental recovery and a likely time profile of production.

Economic viability is investigated with and without tax and royalty considerations for each reservoir to provide some insight into the potential impact of fiscal incentives on ultimate recovery and rates of production. Results by reservoir are then aggregated to determine overall provincial potential. The economic analysis also develops the price per barrel (supply price) required to recover all costs of development and operations for each reservoir.

The results of the evaluation of the potential in Alberta are extrapolated to other provinces and the territories to provide an estimate of the likely level of recovery from enhanced recovery processes for Canada as a whole.

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CHAPTER 1

PETROLEUM SUPPLIES IN PERSPECTIVE

Estimates of world supplies of petroleum from conventional sources have varied considerably over the years as indicated in Table 1.1. Estimates have ranged from 400 billion barrels to 3.6 trillion barrels with recent estimates centring on a figure of 2 trillion barrels of recoverable oil.[1] Even higher estimates than shown in Table 1.1 of some 4 trillion barrels recoverable are supported by Russian estimates of 11 trillion barrels of original oil in place presented in 1976.[2] If we use 1977 production rates as a base and assume 7 percent growth in production each year, these reserves (2 trillion) translate into 28 years of petroleum supplies.[3] The effective life of petroleum supply is increased in the following ways:

- additions to reserves due to new discoveries
- additions to reserves from reassessment of oil volumes in established reservoirs
- additions from increased ability to recover oil
- increasing the longevity of the reserves base through conservation

It seems likely that the rate of new discoveries on a world scale must begin declining from historical levels. This is because the historical rate at which reserves have been added has been strongly influenced by the giant fields (greater than 500 million barrels) in the Middle East. The likelihood of another 'Middle East' is fairly small, although some potential remains offshore and at greater depths onshore. However, given the proportion of the world that has now been

TABLE 1.1

ESTIMATES OF ULTIMATE WORLD RESERVES OF CRUDE OIL

Year	Source	Ultimate Reserves 10^9 barrels
1942	Pratt, Weeks & Stebinger	600
1946	Duce	400
1946	Pogue	555
1948	Weeks	610
1949	Levorsen	1,500
1949	Weeks	1,010
1953	MacNaughton	1,000
1956	Hubbert	1,250
1958	Weeks	1,500
1959	Weeks	2,000
1965	Hendricks (USGS)	2,480
1967	Ryman (Esso)	2,090
1968	Shell	1,800
1968	Weeks	2,200
1969	Hubbert	1,350-2,100
1970	Moody (Mobil)	1,800
1971	Warman (BP)	1,200-2,000
1971	Weeks	2,290
1971	U.S. National Petroleum Council	2,670
1972	Warman	1,900
1972	Bauquis, Brasseur & Masseron (Inst. Fr. Pet.)	1,950
1972	Linden	2,950
1972	Weeks	3,650
1975	Moody & Esser	2,000
1975	Adams & Kirby (BP)	2,000
1975	Sickler (Shell)	1,190-1,410
1975	Moody (Mobil)	2,030
1976	Klemme (Weeks)	1,900

SOURCE: Orlo E. Childs, "Implications for Future Petroleum Exploration," and R. G. Seidl, "Implications of Changing Oil Prices on Resource Evaluations," both in The Future Supply of Nature Made Petroleum and Gas.

J. D. Moody and R. W. Esser, "An Estimate of the World's Recoverable Crude Oil Resources," Ninth World Petroleum Congress, (London: Applied Science Publishers, 1975), vol. 3.

M. Grenon, "Global Energy Resources," in Annual Review of Energy, eds. Jack M. Hollander and Melvin K. Simons (California: Annual Reviews Inc., 1977), vol. 2, p. 78.

explored to some extent, it seems unlikely that many additional isolated giant fields will be discovered. These fields represent 1 percent of the total but contain 75 percent of world reserves and have thus been quite significant in the past.[4]

Reassessment of oil volumes in established reservoirs occurs because information gleaned from production profiles allows more accurate estimation of oil in place and in general this has resulted in significant upward revisions of past estimates. Allowing for these revisions significantly alters the profile of world rates of discovery as shown by Figure 1.1. However, improvements in methods of initial reserves estimation means that this source of reservoir additions will also probably decline in the future. Conservation and enhanced recovery, however, may have more impact on the petroleum life index (28 years) in future. Successful conservation efforts reducing the growth rate of production to 4 percent would extend our life index of petroleum availability by 10 years. On the other hand, increasing the recovery factor on average from 30 to 31 percent would increase reserves by 66.6 billion barrels. An increase in the average world recovery factor of 10 percentage points would therefore mean 666 billion barrels of additional reserves which yields 6 additional years of supply (from 38 to 44) if production rates are assumed to grow at 4 percent per year. On a world scale, this roughly estimated potential for enhanced recovery thus appears significant both absolutely and relative to the potential from conservation alone.

The potential is greatest in the Organization of Petroleum Exporting Countries (OPEC) both because current remaining reserves are concentrated there (see Table 1.2) and because the reservoirs are generally more homogeneous than those in North America which is likely

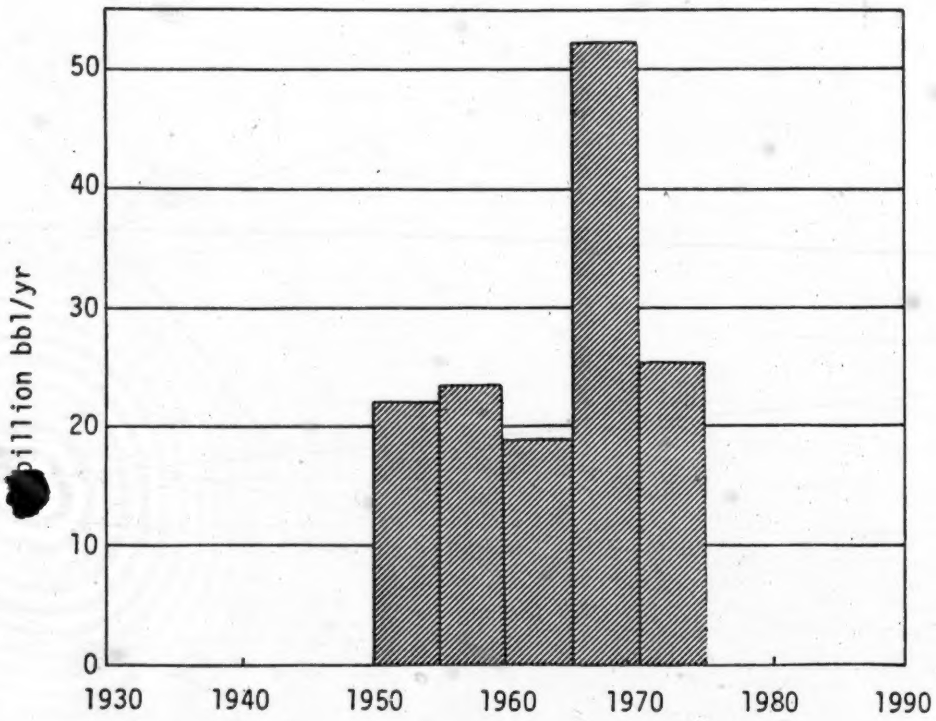


FIGURE 1.1a: Five year averages of rates of oil discovery when both new discoveries and reassessments are credited to the year in which they are made.

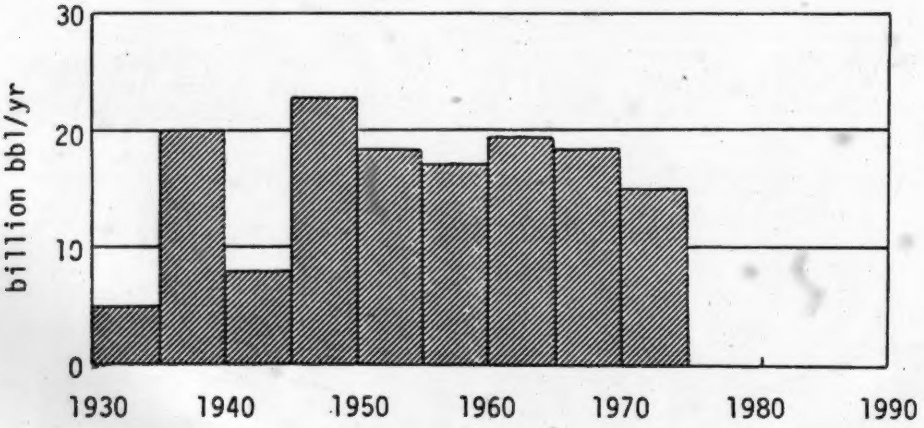


FIGURE 1.1b: Discovery rates are different when revised estimates of oil in place are credited to the year in which the field was discovered.

SOURCE: Andrew R. Flower, "World Oil Production," Scientific American, March 1978.

TABLE 1.2

WORLD OIL RESERVES AND PRODUCTION
1975

	Proven Recoverable Reserves Remaining (billion barrels)	Cumulative Production (billion barrels)
Saudi Arabia	152	23
Other Middle East	208	61
Other OPEC	90	55
North America	40	133
Other Non-OPEC	65	19
Communist Areas	103	50
Totals	658	341

SOURCE: Andrew R. Flower, "World Oil Production," _Scientific American_, March 1978, no. 3.

to make them more susceptible to enhanced recovery operations. North American potential is not insignificant, however, and a number of estimates for the United States have been provided in recent years as shown in Table 1.3.[5] The terminology associated with various phases of oil production is discussed in detail in section 3.4. Estimates of "enhanced oil recovery" potential reported in this chapter refer to recovery using any methods beyond the standard primary and secondary (waterflood) stages of production. A striking characteristic of these estimates is their variation. They range from 8 billion barrels, or 2.9 percent of the oil viewed as the target for enhanced oil recovery (EOR), to 110 billion barrels or 39.6 percent of the target oil. A very rough estimate of the range of possibilities in Canada may be made by applying the recovery percentages implied by the American estimates to the target oil in place in Canada. This is done in the last column of Table 1.3 where it is shown that potential ranges from 1.0 billion barrels to 13.7 billion barrels. As a proportion of remaining proven reserves (6.7 billion barrels) this range is from one-sixth to two times our present assured supplies.[6]

The upper estimate of our American survey is, however, extremely optimistic to say the least. A more conservative in-depth estimate of American potential is provided by the National Petroleum Council (NPC) 1976 publication, Enhanced Oil Recovery.[7] The potential at various oil price levels and technical performance levels is shown in Table 1.4. The third row applies the implied recovery percentage to the target oil in Canada with a resulting range of from 0.4 billion barrels at the low performance and price levels to 4.0 billion barrels at the high price and performance levels. Even the 0.4 billion barrels estimate is not insignificant since it represents about a year's production at current production rates.

TABLE 1.3

ESTIMATES OF EOR POTENTIAL

Source	Oil Price $/bbl constant dollars as of date of estimate	U.S. Estimated EOR Potential billion bbl	Estimated EOR as % of Target Oil[a] % of 278 billion bbl	% Applied to Canada's Target Oil[a] % of 34.7 billion bbl (CPA)
Oil Companies 1		15	5.4	1.9
2		25	9.0	3.1
3		18	6.5	2.3
4		110	39.6	13.7
5		25	9.0	3.1
FEA PIR[b] (1974)	11	57	20.5	7.1
FEA[c] (1975)	12-13	65	23.4	8.1
EPA[d] (1975)				
Low		15	5.4	1.9
High		25	9.0	3.1
FEA[e] (1975)				
Low	11	57	20.5	7.1
High	11	65	23.4	8.1
NPC[f] (1976)				
Base Case	15	13	4.7	1.6
ERDA[g]				
Base Case	11.63	11.9	4.3	1.5
	13	13.1	4.7	1.6
Base Case With	11.63	26.2	9.4	3.3
ERDA R & D	13	30.1	10.8	3.7
OTA[h] (1977)				
Low productivity	11.62	8.0	2.9	1.0
	13.75	11.1	4.0	1.4
High productivity	11.62	21.2	7.6	2.6
	13.75	29.4	10.6	3.7

SOURCE: This table is adapted from Lewin & Associates, *The Potential and Economics of Enhanced Oil Recovery*, for Federal Energy Administration (FEA), April 1976; and Office of Technology Assessment (OTA), *Enhanced Recovery of Oil and Devonian Gas*, U.S. Congress, June 1977.

[a] Target oil is defined as probable original oil in place minus production to date and remaining proved reserves that would be recoverable by conventional methods.

[b] *Project Independence Report*, Federal Energy Administration, November 1974.

[c] Lewin & Associates, *Review of Secondary and Tertiary Recovery of Crude Oil*, for FEA, June 1975.

[d] Mathematica, Inc., *The Estimated Recovery Potential of Conventional Source Domestic Crude Oil*, for U.S. Environmental Protection Agency, May 1975.

[e] Lewin & Associates, *The Potential and Economics of Enhanced Oil Recovery*, for FEA, April 1976.

[f] National Petroleum Council, *Enhanced Oil Recovery*, Dec. 1976.

[g] Lewin & Associates, *Research and Development in Enhanced Oil Recovery*, Nov. 1976.

[h] *Enhanced Recovery of Oil and Devonian Gas*, OTA, U.S. Congress, June 1977.

TABLE 1.4

ESTIMATE OF CANADIAN EOR POTENTIAL BASED ON U.S. ESTIMATED RECOVERY FACTORS

	Oil Prices $/bbl (constant 1976 dollars)											
	10			15			20			25		
	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
NPC Estimate of												
Total U.S. Incremental Recovery[a] (billions of bbl)	3	7.5	13	6	13	26	9	21	31	12	23	33
U.S. Recovery as Percentage of Target Oil 278 billion bbl (%)	1.1	2.7	4.7	2.2	4.7	9.4	3.2	7.6	11.1	4.3	8.2	11.9
Percentage Applied to 34.7 billion bbls. Target Oil in Canada (billions of bbl)	0.4	0.9	1.6	0.76	1.6	3.3	1.1	2.6	3.9	1.5	2.8	4.1

---

[a] National Petroleum Council, Enhanced Oil Recovery, 1976.

Several direct estimates of Canadian EOR potential have been attempted though not on the scale of the NPC effort. The results of this work are presented in Table 1.5. These estimates are relatively encouraging since even the conservative National Energy Board (NEB) estimate of 1.54 billion barrels represents about 3 years production at current producing rates. However, the methodology used in developing these projections was circumscribed by time and resource limitations and is necessarily approximate in nature. It is probably one step better than applying U.S. recovery percentages to Canadian remaining oil in place, but beyond that, little can be said. Our present endeavour is to refine the estimation procedures a little more and attach meaningful cost information to the resulting estimates.

The procedure that has been developed to accomplish this objective is based on in-depth analysis of individual reservoirs in Alberta. Every reservoir listed in the Energy Resources Conservation Board's (ERCB) 1976 reserves estimate was evaluated on an individual basis. Reservoirs that appeared profitable under the technological and economic assumptions described below were aggregated to provide overall estimates for the province. All cost data used in the analysis are in constant 1978 dollars. Estimates of total Canadian potential were developed by extrapolation of the Alberta results.

The analysis took no account of enhanced recovery activity that is already under way because it is not possible to get complete and up to date information on enhanced recovery projects. Projects that were reported as either in the pilot stage or in the planning stage are shown in Figure 1.2. The figure is based on the 1978 enhanced recovery report in the Oil and Gas Journal and shows the preponderance of thermal and miscible gas projects in Alberta and Saskatchewan. Thus the

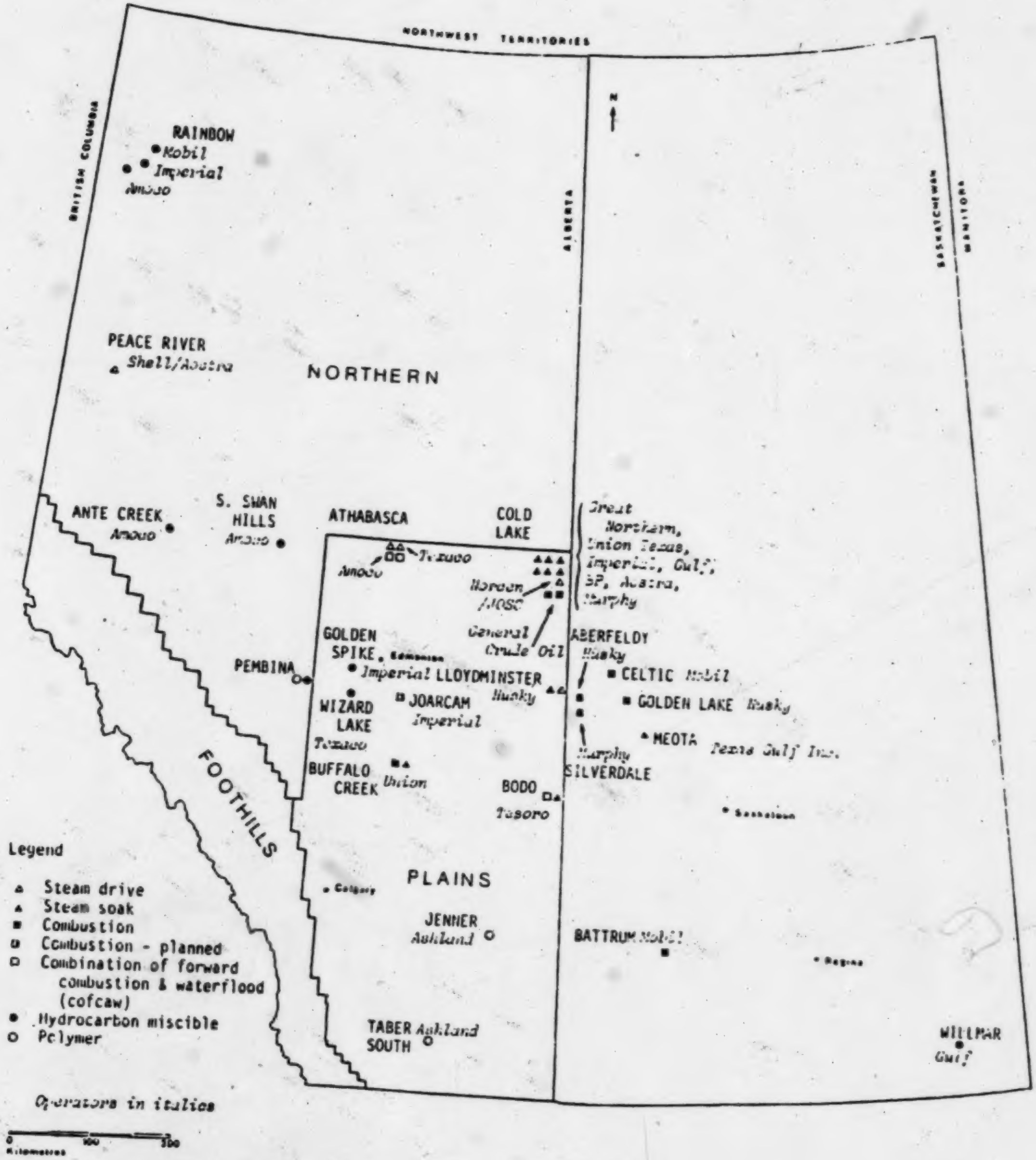


FIGURE 1.2: Enhanced Oil Recovery Activity in Canada

SOURCE: Oil and Gas Journal, March 27, 1978

TABLE 1.5

DIRECT ESTIMATES OF EOR POTENTIAL IN CANADA

	Enhanced Recovery Potential (billions bbl)
Strom-Bray-Berndtsson (ERCB 1973)[a]	2-4
Wyman (Shell 1974)[b]	3-6
Stacy (AMOCO 1975)[c]	6.3
CPA-IPAL (1976)[d]	2-4
Imperial Oil (1976)[e]	2.3
D & S Petroleum Consultants (1976)[e]	2.9
National Energy Board (1977)[e]	1.54
Imperial Oil (1978)[f]	2.25

[a] N. A. Strom, J. A. Bray, and N. G. Berndtsson, "Enhanced Recovery Trends in Alberta," Journal of Canadian Petroleum Technology, July-September, 1973.

[b] "Tertiary Recovery Presents Challenge to Produce More Crude From Older Fields," Oilweek, Dec. 2, 1974, p. 12.

[c] "Improved Recovery Possible," Edmonton Journal, April 25, 1975, p. 37. Quoted in D. DePape, "Canada's Future Oil Supplies--Sources, Availability and Real Resource Costs," 1975.

[d] Submission to Department of Energy and Natural Resources by Canadian Petroleum Association and Independent Petroleum Association of Canada, Calgary, July 14, 1976.

[e] Canada, National Energy Board, Canada's Oil, (Ottawa: National Energy Board, 1976), p. 13-15.

[f] Submission to the National Energy Board in the Matter of Canadian Oil Producibility and Domestic Requirements, April 1978.

estimates developed here include those projects that are already underway or in early planning stages.

The extent to which this activity increases in future will depend on the relative attractiveness of enhanced recovery within the broad range of alternative investment opportunities available to industry. In addition to estimating the physical quantity of hydrocarbons that may be available from application of tertiary processes, this study attempts to evaluate the likely profitability of such activity to society and to private industry, in order to provide perspective on it as an investment alternative.

1.1 Preview of Results

The analytical results of the procedure developed below to estimate potential and costs of enhanced oil recovery are presented in detail in Chapters 5 - 7, and Appendix E. The Alberta potential is 2.4 billion barrels, producible over 28 years at an average discounted cost per barrel of approximately $14. This result is based on an assumed domestic price of oil in real terms of $20 per barrel over the period of the analysis; and a real discount rate of 8 per cent.

Extrapolation of the forecast to Canada as a whole increases the estimated potential to 4.0 billion barrels. This potential would allow annual additions to domestic oil production that, according to our assumed producibility schedules, would peak in 1992 at 240 million barrels per year (656,000 barrels per day) and decline thereafter until the full potential is exhausted within the first decade of the twenty-first century.

Some perspective on the significance of this contribution to Canadian energy supplies is provided by Table 1.6. This table presents

TABLE 1.6

POTENTIAL AND COSTS OF ALTERNATE CANADIAN ENERGY SOURCES

Energy Source	Estimated Cost 1980 dollars per barrel of oil equivalent[a]	Ultimate Recoverable billion barrels of oil equivalent[b]	Expected Annual Production billion barrels of oil equivalent 1985	1990
CRUDE OIL				
Conventional[c]		20.0	.441	.302
Primary[d]	11	-	-	-
Secondary[e]	4	-	-	-
Enhanced Recovery[f]	17	4.0	.158	.392
Northern Frontier[g]	18	13.6	.380	.380
Eastern Frontier[h]	20	10.9	.200	.240
Synthetic (Oil Sands)[i]	20	29.0	.146	.305
Liquids from Coal[j]	38	-	-	-
Imported Oil[k]	30	-	-	-
NATURAL GAS				
Conventional[l]	6	19.0	.538	.395
Northern Frontier[m]	11	14.2	.075	.123
Eastern Frontier[n]	11	10.8	.000	.167
Synthetic (from Coal)[o]	29	-	-	-
COAL[p]	13	416.0	.233	.549

NOTES TO TABLE 1.6

[a]Costs in Canadian dollars per unit are as of date indicated in each note below. For comparability all costs were escalated to 1980 at 10 per cent per year, and rounded to the nearest dollar. Natural units were converted to barrels of oil equivalent using the following conversion factors:

6000 CU FT of natrual gas is approximately equivalent to 1 barrel of oil,
.240 short tons of coal is approximately equivalent to 1 barrel of oil.

[b]Estimates of ultimate recoverable resource and expected production (except those for enhanced recovery which are from this study) are based on Energy Supply to the Year 2000 the Second Technical Report of the Workshop on Alternative Energy Strategies (WAES), William F. Martin, Editor, June, 1977, the MIT Press Cambridge, Massachusetts, and London, England. Cases where no estimate is available are indicated on the table with a dash.

[c]Quantities associated with primary and secondary production processes were not estimated separately by WAES. Approximately one quarter of conventional recovery may come from secondary processes.

[d]We assumed a total cost per barrel of $10 in 1979. This estimate included finding, development and production costs. Estimates of finding costs vary considerably. They were estimated at $8.46 per barrel in Russell S. Uhler Oil and Gas Finding Costs, Canadian Energy Research Institute, Study No. 7, September, 1979. A report in the Globe and Mail January 30, 1980 quotes D.M. MacDonald, Director of IPAC, estimating finding costs at $5.00 per barrel. A survey of costs reported in Oilweek, February 11, 1980, p.48 yields the following averages over the period 1974-1978.

Finding Costs	$6.36
Development Costs	$5.87
Production Costs	$1.10

However, the average total cost per barrel of $13.33 includes costs of Frontier sources.

[e]The Cost is based on a 1976 estimate of $2 per barrel, a proxy for results that ranged from $0.248 per barrel to $2.349 per barrel. The estimating procedure did not incorporate finding costs and the development costs assumed are incremental to those that would be required anyway for primary production. The source of the reported cost is G.C. Watkins, "Costs of Supply: Oil Enhanced-Recovery Schemes in Alberta", Bulletin of Canadian Petroleum Geology Vol. 25, No. 2, May 1977, P. 433-440.

[f]The cost is based on overall results of this study, $14 per barrel in 1978 dollars. The $14 figure is an average of calculated costs for Alberta reservoirs weighted by the proportional contribution of each reservoir to total projected production.

[g] The estimate includes costs of both onshore and offshore production. W. Hopper, President of Petro Canada was quoted as estimating Frontier costs as $18.10 per barrel "at least" in the Calgary Herald, April 20, 1977. The Toronto Globe and Mail reported costs of $19.75 per barrel at the wellhead, September 26, 1979 which is essentially the same allowing for inflation. Some industry representatives suggested that the cost of Eastern Frontier (offshore) development might be slightly higher than in Northern Canada. Also, since some of the Northern production is here assumed to be onshore we have allowed a $2 per barrel differential between the two sources.

[h] Based on costs of Northern Frontier oil, discussed in note g, plus an arbitrary $2 per barrel differential to allow for higher estimated costs.

[i] Synthetic crude from the Athabasca oil sands was estimated to cost 14-16 dollars per barrel in Oil Sands and Heavy Oils: The Prospects, Energy, Mines, and Resources Canada, Report EP77-2, 1977, P.32. This range was supported by estimates of from $12-22 per barrel depending on assumed rates of discount, developed in C.Z. Slagorsky, Some Supply Price Estimates for Synthetic Crude Oil in Canada, Canadian Energy Research Institute, Calgary, April, 1978. We escalated a price of $15 per barrel to 1980.

[j] B.A. Rahmer "The Threatening Crisis" Petroleum Economist February, 1980, PP.49-51. The range quoted in 1979 U.S. dollars is $30-37 per barrel which, at an exchange rate of .86, becomes $35-43 Canadian. We escalated the lower bound to 1980 to provide the most unfavorable comparison to our enhanced recovery estimate.

[k] Petroleum Economist, February, 1980, p.46. The price quoted is $26 per barrel in U.S. funds for Saudi Arabian Light Crude. This is $30.23 in Canadian dollars using an exchange rate of .86.

[l] The base price for this calculation was an average of the 1979 average price at Toronto of $1.77 per MMBTU and the 1980 price of $2.10 per MMBTU. This base price was $1.95, from which was deducted transportation costs of $0.60 per MMBTU and a royalty estimate of 25%. The prices were provided by the department of Fiscal Policy and Economic Analysis, Alberta Treasury.

[m] A 1976 forecast of $2.35 per Mcf in the marketplace is contained in National Energy Board, Reasons For Decision, Northern Pipleines, June 1977. Deducting an estimate of $0.75 per Mcf for transportation and 25% of the remainder for royalties leaves us with an estimated field price of $1.20 per Mcf, which was then escalated to 1980 and converted to barrels of oil equivalent.

[n] In the absence of reliable estimates we have adopted the estimates discussed in note m. Some industry representatives expressed the opinion that Eastern offshore development will be somewhat more costly but were not able to suggest a differential.

[o] B.A. Rahmer "The Threatening Crisis" Petroleum Economist, February, 1980, PP.49-51. The range quoted, in 1979 U.S. dollars, is $23-35 per barrel which at an exchange rate of .86 becomes $26-41 Canadian. We escalated the lower bound price to 1980 to provide the most unfavorable comparison to our enhanced recovery estimates.

[p] This is an average of minimum F.O.B. mine-site prices that would allow profitable operation in four typical Canadian sources listed below. They are from Canadian Resourcecon Ltd., Potential Markets for Thermal Coal in Canada, 1978-2000, Study Number 4, P.13, Calgary, Canadian Energy Research Institute, June, 1979.

	$/ton(short)
Bienfait, Saskatchewan	6.00
Drumheller, Alberta (surface mined)	8.00
Coalspur, Alberta	20.00
Cape Breton, Nova Scotia	35.00
Average	17.25

some very general estimates of alternate energy source costs and quantities. The reserves and production estimates are all from the same source, the Workshop on Alternate Energy Sources, and are therefore at least internally consistent. The cost estimates are less reliable since they are taken from various sources which undoubtedly employed differing estimation procedures. Moreover, our efforts to make all costs comparable on a 1980 basis probably distort reality to some extent since each source has been subject to it's own rate of cost increase, whereas we have brought all costs forward to 1980 using a 10 per cent per year rate of increase. However, with these caveats firmly in mind, some interesting comparisons can be drawn.

First, we see that the ultimate potential for enhanced recovery is the smallest of the alternatives listed with the exception of synthetic oil or gas from coal, and imported oil, neither of which can be reliably estimated at this time. Nonetheless the potential contribution to annual production is significant, particularily around 1990, which may well be a critical period in the transition of the world economy from fossil fuels to alternate energy sources. The projected cost of oil from the tertiary application investigated here is in the mid-range of the alternates shown implying that enhanced oil recovery is a viable option for Canada and merits continued development by industry and government.

1.2 Organization of the Study

Chapter 2 following discusses the framework within which the economic analysis is couched. The framework is that of Benefit-Cost Analysis and the relevant problems are discussed in considerable detail.

Chapter 3 is a brief review and summary of the fundamentals of reservoir production and enhanced oil recovery.

Chapter 4 develops both the physical production models and the economic evaluation procedure. The purely technical aspects of the production models are segregated in Appendix D. Economic aspects of the models are drawn from the discussion in Chapter 2 and supplemented by the derivation of costs and tax considerations in Appendices B and C respectively.

The principal analytical results of the study are presented in Chapter 5. The implications for both Alberta and Canada as a whole are presented under a set of 'base case' assumptions. These are, a domestic oil price of $20 per barrel in constant 1978 dollars, an assumed rate of return to industry of 8 per cent in real terms, and the basic costs of development and production outlined in Appendix B.

The sensitivity of the base case results to changes in the oil price assumption are set out in Chapter 6. The entire analysis was repeated for price assumptions of $15 per barrel, which was fairly close to the wellhead price being received by producers in late 1979 ($13.75 per barrel with increases scheduled for January 1980), and $25 per barrel. In addition, selected results of a $100 per barrel price are presented.

Chapter 7 presents a summary of the main conclusions of the analysis together with comments on the implications they hold for policy development.

Appendix A provides a brief description of the data base and the screening procedure used to isolate the reservoirs technically amenable to enhanced recovery. It also describes the procedure used to extrapolate the Alberta results to the country as a whole.

Appendix B describes the manner in which costs of field development were assembled and specifies the assumed costs for all aspects of each process used.

Appendices C and D provide details of the general models described in Chapter 4. Appendix C sets out the manner in which tax and royalty considerations were incorporated. Appendix D expands on the detailed technical relationships in the production models.

Appendix E presents results of further sensitivity analysis. The models were run for differing assumptions regarding, the percentage of oil recovered in each reservoir, the pattern size used in each project, and the level of development costs.

Appendix F is essentially a list of technically and economically promising reservoirs in Alberta.

Footnotes

[1] The wide range of estimates occurs because differing estimating techniques may be used and because differing assumptions regarding the economics and technology of recovery are implicit in the estimates. The term 'reserves' is defined in a number of ways by different groups and no attempt to reconcile definitions is attempted here. For the overview purpose of this chapter, the term should be viewed as applying to oil that would be recoverable by conventional methods under the technological and economic conditions existing at the time the estimate is made. It should be noted that 'ultimate reserves' as used here also include estimates of recoverable oil from future discoveries. However, the estimates do not allow for significant increases in recoverability due to enhanced methods.

[2] I. I. Nesterov, and F. K. Salmanov, "Present and Future Hydrocarbons of the Earth's Crust," in The Future Supply of Nature Made Petroleum and Gas, ed. R.F. Meyer (New York: Pergammon Press, 1977).

[3] 1977 production was 22.6103 billion barrels; Petroleum Economist, April 1978, p. 72. Production growth rates averaged 7.8 percent between 1960 and 1973, dropped in 1973 and 1974, but recovered to 6.7 percent between 1975 and 1976; World Oil, February 15, 1977, p.132.

[4] H. D. Klemme, "World Oil and Gas Reserves from Analysis of Giant Fields and Petroleum Basins (Provinces)," in The Future Supply of Nature Made Petroleum and Gas.

[5] Oil considered as a target for EOR is original oil in place minus cumulative production to date minus remaining proven reserves (which will be produced with established methods). In the U.S. this is 401 - 101 - 22 = 278 billion bbl. In Canada it is 49.3 - 7.9 - 6.7 = 34.7 billion bbl. (as of December 31, 1976); Canadian Petroleum Association, Statistical Handbook (Calgary: Canadian Petroleum Association, 1977), Section II, Tables 4 and 17.

[6] The 6.7 billion refers to proved reserves (oil recoverable from known reservoirs under current technology and economics). The figure used in Table 1.3 of 34.7 billion bbl refers to total oil that may be viewed as a target for enhanced recovery (see note 5).

[7] Even this publication is considered optimistic by some since it applies a standardized method of estimating recovery to all reservoirs which pass a rather basic screening test, whereas actual recovery is hampered in individual cases by particular reservoir characteristics. Others, however, feel that the NPC approach resulted in pessimistic estimates.

CHAPTER 2

ECONOMIC EVALUATION

2.1 The Economics of Exhaustible Resources

Oil is a non-renewable resource and the economic framework within which depleting resources are analysed is, in a very general way, the starting point for the analysis of this study. The relationship between the detailed engineering oriented production models used here and the sophisticated optimization models used in theoretical analysis is somewhat tenuous but real nonetheless. It will be helpful to consider, briefly, the nature of this relationship.

Specification of the firms' problem in maximising profits over time is some variant of 1).[1]

1) $$\text{MAX} \int_{t=0}^{N} (pq - TC)\, e^{-rt}\, dt$$

$$\text{s.t} \int_{t=0}^{N} q(t) \leq R(t) \text{ and } q(t),\ R(t) \geq 0$$

where $P(t)$ = price at time t

$q(t)$ = quantity produced at time t

$TC(t)$ = total cost of production (extraction) at time t

$R(t)$ = total recoverable quantitiy of oil in the reservoir given current technical knowledge and foreseeable economic conditions

r = discount rate

N = life of project

In the case of oil, total cost of extraction from a particular reservoir is an increasing function of production $(\frac{\partial TC}{\partial q} > 0)$ and as production occurs, costs rise at an increasing rate due to the pressure drop in the reservoir $(\frac{\partial^2 TC}{\partial q2} > 0)$.[2] The latter notion leads to the concept of the maximum efficient rate (MER) of production. Production above this rate may cause a reduction in total recoverable oil from the reservoir because of a too rapid drop in pressure.[3]

The problem is to choose among varying time profiles of production and investment the one that maximizes the present value of a reservoir and under some strict assumptions it is mathematically solveable. Investigation of the solution to this problem has led to an interesting conclusion.

In a competitive environment the market price of the resource minus production costs (the economic rent) will increase at a rate equal to the rate of interest. This is intuitively plausible since oil in the ground is an asset like all others and must earn the same (risk adjusted) rate of return as all others if asset markets are to be in equilibrium.

For an illustrative two period case, we have:

2) $P_1 = P_o (1 + r)$

where P_o = the rent or profit from the production and sale of one unit of the reserve in the present

P_1 = expected profit from the sale of one unit of the reserve in the future

r = the market rate of interest

If P_1 is less than P_o (1+r), resource owners will increase current production, investing the proceeds at rate r. The increase in supply will put downward pressure on the current price. If P_1 is greater than P_o (1+r) current production will be postponed but the resulting reduction in supply will cause P_o to increase. Intertemporal equilibrium requires the future value of oil in the ground to be the same as what would be realized if the oil were produced today with the proceeds invested at the market rate.[4]

This relation between present and future profits can be rearranged to introduce the associated concept of user cost.[5] User cost is defined as the present value of the profit that would be earned on an extra unit if its production were postponed to the best future date. In the simple two period case of Equation 2

$$3) \qquad \text{User cost} = P_o = \frac{P_1}{(1 + r)}$$

Equation 3 says clearly that user cost of a unit of production now is the opportunity cost of foregone future profit.

A specfic application of this concept to oil reservoir development has been presented by Paul Davidson, who identifies three types of user cost.[6]

a) User cost inherent in finite, non-perishable materials, substitutable over time

b) User cost of ultimate recovery

c) User cost of the rule of capture

The first type is that illustrated by Equation 3. The second type relates to the relationship between ultimate recovery and production rates. This relationship is less emphasized in the current engineering literature (see Sec. 3.3.1) especially in discussion of tertiary recovery methods that utilize some form of pressure maintenance. The third type is due to the common property nature of oil reservoirs which could allow neighbouring wells to 'capture' some of the oil that lies under the surface area allotted to a given producer. This type of user cost can be eliminated by unitization practices. Therefore, insofar as tertiary recovery is concerned, only the general user cost concept related to the substitutability over time of finite non-perishable resources has relevance.

It should be noted, however, that user cost is a concept that comes out of the optimizing procedure establishing the optimal rate of production. It is, in essence, a first order condition that says profit, over time, is maximized when the producer produces at a rate that equates marginal current profit with marginal user cost. Since our procedure (discussed below) assumes some optimum rate of production for each reservoir regardless of changes in future price expectations the concept is not directly relevant to our estimation. It should also be noted that since user cost depends on future prices and costs of production it is unknown in the present. The resource owner bases his estimate of user cost on expected prices and production costs. In the models developed below future prices and costs (in real terms) are assumed constant at particular levels. This means that foregone future profit (discounted) is always less than current profit; a situation that theoretically suggests there would be a strong incentive to rapid production. That is, in the real world, projects would be brought on stream and produced as quickly as possible, since the profit could be reinvested and the total return would be greater than if production was delayed to a future period. This is a theoretical limitation of the constant price assumption. However, as discussed in Chapter 4, below, we adopted a schedule of project initiation that brings on stream (in descending order of profitability) an arbitrary percentage of projects each year. Furthermore the models incorporate production assumptions that are unrelated to price once the basic test of profitability has been passed. Therefore, the fact that our formulation involves marginal user cost that is always less than marginal current profit, though it holds behavioural implications in the real world, has no significance for our estimating procedure. It is perhaps worth mentioning that Scott has pointed out the difficulties of empirical estimation of user cost and to our knowledge no attempts to utilize the concept in empirical work in the natural resource field have been made.[7]

The considerations above do not mean that the concept of user cost can be ignored when drawing analytical or policy conclusions from the eventual estimates. Therefore, the conclusions set out in Chapter 7 deal with the implications of user cost in some detail in circumstances where the price assumptions of our modelling are relaxed.

Returning to Equation 1, optimization requires knowledge of the functional relationship between costs and output. Presumably increasing costs through investment (such as adding wells or using more chemicals) will increase the rate of production (q) and perhaps also the total recoverable oil (R). Precise knowledge of the nature and extent of this relationship would allow us to select the optimum path for investment and production given a set of input and product prices. The solution would identify the optimum amount of recoverable oil, the optimum time profile of investment and production required to recover it and the economic life of the recovery project. Results for individual reservoirs could then be aggregated to determine the regional and national potential for 'optimal' enhanced development of existing reservoirs.

Unfortunately, the technology of the various enhanced recovery processes is largely in the development stage and uncertainty regarding individual reservoir characteristics would in any case preclude attempts to optimize along the above lines. Therefore, an alternative estimating procedure is required. The production models described in Chapter 4 are based on the results of ongoing experimentation in field and laboratory as reported in the engineering literature, and also on the informed judgement of a large number of reservoir engineers specializing in enhanced recovery. The basic structure of the models was developed by the National Petroleum Council and Lewin and Associates, refined somewhat by the Petroleum Recovery Institute, and adapted by the author to the particular situation and circumstances in Alberta.[8] These production models make an 'informed guess' of the amount of recoverable oil in each reservoir which is to some extent determined by individual reservoir characteristics. They then apply production assumptions which differ by recovery process but which in each case establish a particular production and investment profile over time, and the 'life' of the project. Finally, an economic overlay of input and product prices is applied to each reservoir and profitable projects are added to the reserves base.

Comparing this procedure to the theoretical optimization model of Equation 1 reveals it as an attempt to specify a reasonable functional relation between investment and associated production for each enhanced recovery process as it would operate in individual reservoirs. Instead of choosing the economically optimum path from a number of alternatives, we specify an assumed optimum path from an engineering point of view, and determine whether or not it is economically viable under several different sets of assumed input and product prices. Economically viable reservoirs are then aggregated to provide an estimate of overall potential and the sensitivity of the results to changes in initial assumptions is determined. The details of the production and economic models are provided in Chapter 4. The estimation results appear in Chapters 5, 6, and Appendix E. The remainder of this chapter expands the theoretical background of the economic procedure utilized to evaluate individual projects.

2.2 Cost Benefit Analysis

Oil is a common property resource, located and produced under conditions of incomplete information, involving external effects, and varying degrees of monopoly power. Such conditions preclude complete reliance on the free market as a vehicle to maximize welfare, and necessitate analysis based on a more encompassing approach which allows explicit consideration of these problem areas. Such an approach is available in the form of cost benefit analysis.

2.2.1 Introduction

Cost benefit analysis is essentially an application of theoretical welfare economics arising pricipally from the need to put a value on benefits and costs of activities that are not adequately reflected in market prices. The failure of the market system in particular instances is attributable to a number of circumstances, primarily the existence of externalities and public goods, common property resources, and market imperfections such as immobile resources, incomplete knowledge, or deviations from a competitive environment due to any of the circumstances that impart an element of monopoly to economic activity. Market failure may mean that some of the values entered in economic calculations of Equation 1 are inadequate, and particularly in the case of public investment analysis, require the analyst to make some adjustment to these values. The procedure differs from private investment analysis primarily in the extent to which external costs or benefits are specifically accounted for, and in the possible use of a 'social discount rate' rather than the private firm's required rate of return, the opportunity cost of capital to that firm.

Most applications of cost benefit analysis devote considerable space to discussing benefit evaluation. In our case, the benefits of the projects are primarily definable as the market value of future oil produced through enhanced recovery. Nonetheless, there are some external effects that could be quite significant.

Any firm engaged in an on-going search for oil could realize substantial benefits from even modest increases in recoverability by enhanced recovery techniques since these could increase potential revenue from all future discoveries. But individual firms cannot always be sure of capturing the benefits from tomorrow's application of processes developed today because of limited tenure arrangements and political uncertainties. So they will be hestitant about accepting the full costs of developing such processes. This is not a problem from the social point of view, however, since the public, if it accepts the costs, will eventually reap the benefits in the present or in subsequent generations.

Another major benefit to society from developing expertise in this area lies in rationalizing the planning process. Say, for example, that society develops its collective skills enough to be fairly confident of predicting enhanced recovery potential. The realization of this potential may require research at both the theoretical and applied levels. Also material, financial, and human resources will need to be allocated to the activity. The lead time provided by the forecasting procedure will allow these resources to be deployed in an efficient manner. Even if the actual prediction was that the potential was negligible, there would be a significant benefit to society in the form of released research resources directed at more promising alternatives. The earlier this knowledge is made available, the better our future planning will be.

To the extent that security of oil supply is important we may count it as an external benefit of the successful development of enhanced recovery skills. It may be that the most significant contribution of an enhanced recovery capability will come from providing a needed breathing space while the transition to other energy sources is made.

There is, however, a conceptual problem associated with the inclusion of the last two items in the list of benefits. It has to do with the fact that Cost Benefit analysis is a partial equilibrium tool and is, strictly speaking, not applicable to situations where the impact of the 'project' is significant enough to affect macroeconomic variables in the economy. Our usage is appropriate when we restrict ourselves to consideration of individual EOR projects. But consideration of the external benefits discussed above brings us perilously close to viewing the collection of projects as one big project in which case partial analysis becomes questionable. Consideration of such external benefits must therefore be at most qualitative in nature. Benefit for our purpose, is the revenue potential of each project. Potential external costs related to pollution from the recovery processes would, on the other hand, apply to individual projects. We handle this primarily by incorporating costs of pollution abatement in each project.

Other aspects of the cost benefit technique and our use of it here require some comment. These include the choice of disount rates, appropriate investment criteria, and the handling of risk and inflation.

2.2.2 Time and Project Evaluation

In general, projects have differing time profiles of benefits and costs which complicates the problem of choosing from a limited number of investment options. For example, generation of electricity with a nuclear plant involves a large initial investment followed by moderate yearly operating expenditures. A coal-powered generating station would involve lower initial investment but higher operating cost over the life of the plant. A rational choice between two such investment opportunities requires some basis of comparison which takes into account the heavier burden imposed by the project with high 'front end' costs. The standard procedure is to reduce all future expenditures and revenues to a present value through discounting.

The Choice of a Discount Rate

The question of which of several general approaches to the choice of an appropriate discount rate should be used is relatively complex and cannot be discussed thoroughly here. Our purpose is limited to providing the rationale underlying the estimating procedure adopted.

It will be convenient to address this question in two steps. First, why should discounting occur at all (i.e. why should interest rates be greater than 0)? Second, which of a variety of numerical candidates should be used for discounting future benefits and costs? Although the discussion is couched in terms of deciding among a choice of discount rates, it should be remembered that the underlying issue is really to what extent present generations might be expected to make provision for future generations through control of the level of current investment or use of current resources. Low discount rates favour future generations by justifying high levels of current investment the benefits of which will be valued to a more distant future horizon. High discount rates favour the present by discouraging investment for the production of more distant future benefits, and thus releasing current resources for consumption purposes, the benefits of which are realized by today's consumers.

One of the earliest explanations of a rationale giving rise to a positive interest rate runs in terms of the productivity of capital. A man may catch five fish in a day by snatching them from a stream, but if he takes time off from fishing to make a fishing rod, his catch per day is likely to increase significantly. In fact, it must be so, since our fisherman must live during the period when he is not fishing but rather constructing a fishing rod and he must therefore borrow food from others which he is then required to pay back by catching more fish than he otherwise would have. He has accepted a cost related to a time interval in order to increase his 'production' of fish through the use of capital (fishing rod) in a more roundabout production process (that is, producing one good first then using it to produce another). Generally, in a complex economy, interest may be viewed as a return for the increased productive efficiency provided by resources fashioned into capital goods rather than into goods for immediate consumption.

So far, one important aspect of this process has been neglected, namely the 'borrowed' fish required to keep our fisherman going while he designs and constructs his fishing rod. This sustenance came from other members of the community who are, in effect, saving or sacrificing their own current consumption in order to assist the productive process for the future. Interest, then, is also viewed as the payment necessary to induce such individuals to postpone consumption, a 'reward' for waiting.

The productive attribute of 'real' capital causes entrepreneurial individuals to desire it in order to increase their production. This desire is translated into a demand for financial capital with which to acquire it (or in our simplistic example, a demand for a means of subsistence, fish, while the real capital is produced). The desire of other individuals to provide for increased future consumption, realized through the reward they get for 'waiting', translates into a supply of financial capital (savings). These potential borrowers and savers are brought together in a bargaining situation in financial capital markets where the interaction of demand and supply ultimately establishes some equilibrium price for financial capital--the market rate of interest. Anyone considering an investment opportunity could evaluate its future prospects by comparison with the market rate since he would always have the choice of lending his money out at this positive rate instead of engaging in the real investment opportunity.

The second question implicitly accepts the existence of positive interest rates and asks which of a number of possible rates should be used for project analysis. Should it be based on some notion of opportunity cost or time preference, or are these the same?[9] The answer will depend on the assumptions of our model and on our point of view--on who is asking the question. The answer for society will be different from the answer for individuals. These considerations lead to four types of rates, as illustrated in Exhibit 2.1.[10]

Let us consider first the benchmark economic model of perfect competition. An equilibrium market rate of interest is established by the interaction of forces of demand and supply in the capital market.

EXHIBIT 2.1

	SOCIETY	INDIVIDUAL
OPPORTUNITY COST	Social Opportunity Costs r_s	Private Opportunity Costs r_p
TIME PREFERENCE	Social Time Preference ρ_s	Private Time Preference ρ_p

POSSIBLE TYPES OF DISCOUNT RATES

An illustrative classification
of possible bases for choice
of appropriate discount rate.

The market rate is the private opportunity cost of capital since this rate is what the individual foregoes when he undertakes real investment as opposed to lending. Moreover, since the rate emerged from a competitive bargaining process, it would presumably represent individual time preference at the margin as well. So at least from a private viewpoint the 'perfectly competitive' model has an unambiguous answer to our problem. The choice between an opportunity cost rate and a rate based on time preference is eliminated since they are the same. In such a world, investment decisions would be relatively uncomplicated. As long as the process operated without major imperfections, one could argue that the market was correctly allocating resources over time. Future generations would be provided by firms with an increased stock of capital equipment allowing them to produce more goods for consumption. Present generations would be foregoing consumption now for a return promised to them or their heirs which just compensated for their time preference.

The first complication in this analysis centres on the possible divergence of private and social opportunity costs.[11] This is attributable to certain well known externalities such as pollution and inadequate institutions governing property rights. In these cases costs external to the firm are imposed on society reducing the social rate of return (rs) below the private rate (rp). The problem is resolvable in theory by ensuring that all costs are internalized to the firm. The second complication has to do with the divergence of opportunity costs and time preference. This is largely due to the existence of a government sector and can be recognized simply by considering the effect of corporate income tax. If shareholders' rate of time preference is ten percent, then a firm facing a fifty percent income tax must engage in investments that earn twenty percent in order to keep annual meetings serene. The implication is that if the government undertakes a project for which it uses resources that otherwise would have been used by firms then the opportunity cost of those resources is really twenty percent. So what rate should be used to discount the benefit and costs of the public project—twenty or ten percent?

In his discussion of the problem, Baumol expresses an admittedly weak preference for the twenty percent rate since he dislikes taking resources from high return uses to put them in low return uses. But he allows that if the rate of time preference is ten percent, then using the higher rate will allocate a smaller amount of productive capital to the future than society desires.

> ...there remains an inescapable indeterminacy in the choice of discount rate on government projects....[12]

The quotation highlights the fact that the problem as it is discussed in the economic literature and reported on here, centres on evaluating public sector projects. From the viewpoint of the private individual or firm, there should be no problem; they would use whatever rate reflected their opportunity costs. These are often approximated by the market interest rate since this rate is a proxy for the foregone alternatives in the market.[13] The reason we have addressed the issue is that the present study is attempting to evaluate a series of private projects from both a private and social viewpoint. The social desirability of enhanced recovery projects may be underestimated if we use only the rate of discount associated with the private opportunity cost of capital.

To recap, we are seeking a basis on which to choose a discount rate which adequately reflects social values. In an imperfect market there is a conflict between the private and social opportunity cost approaches and between the private opportunity cost and private time preference appoach. There is a theoretical solution to both these problems, although they are difficult to apply in practice. We now extend the discussion with a third complication, namely the divergence of private and social time preference rates even in an otherwise perfectly operating economy.

The social time preference rate indicates how today's society values future consumption (our willingness to forego present consumption in order to enjoy future consumption). Society may collectively value the future higher than each individual would for several reasons. First there is the myopia argument suggesting that society should offset the tendency of individuals to discount the future too heavily. Bhagwati disputes this reasoning:

> A system of time discount is popular with economists, but seems to have little justification: after all, the very purpose of prior calculation is to avoid the kind of myopia that the use of time-discount rate implies.[14]

There is, however, some justification for the individual's myopic view of things; namely the always present possibility of imminent death. But for society this argument is less compelling, particularly if the welfare of future generations is to count.

Second, we may cite Marglin's schizophrenic answer, that is, the 'economic man' and the 'citizen' in each of us are in conflict and when expressing our views as to how government should treat the future, we are more generous collectively than we are in private economic decision-making.[15]

Finally, Sen has pointed out that it is quite rational for individuals who prefer consuming to saving, to decline to make sacrifices for the future. From the individual's point of view such sacrifices appear insignificant in the aggregate but reduce the current welfare of the individual. He might be persuaded to provide for the future, but only if he can be assured that everyone else will as well since then there would be some 'impact' to the decision.[16]

For these reasons, then, it is held that the private time preference of individuals as expressed by the market interest rate does not adequately allow for the future. Therefore, government should evaluate public projects using some lower 'social time preference' in order to pass on an equitable amount of productive capacity to the future.

One objection to this suggests that people who make up the market and those who elect the government are the same group and that a specific political decision to contradict the economic decision implies some undesirable inconsistency. But this neglects the fact that economic decisions emerge within a given distribution of wealth and income and it may well be deemed desirable to override a decision arrived at through (unequally shared) dollar voting by the process of political voting.[17]

On a political level, the issue relates to whether a government should act rationally or follow the dictates of public opinion. Should they act in the best interests of the public or should they do what the public wants? A related question is whether or not the 'public' should include unborn generations, in which case one could imagine a heavier vote for the lower discount rates in order to provide for the future.

This leads us to an argument in favour of discounting the future which has to do with increasing affluence over time and the inevitability of diminishing levels of satisfaction from incremental consumption. Since consumption levels seem to increase over time, the satisfaction received by future generations from incremental consumption is presumably less than that received by present generations. If this is correct, it would be reasonable to value future consumption less highly than today's (i.e., discount it). There are two problems with this reasoning as it stands. First, although consumption per capita has shown steady increases in the past, it is not certain that this trend will continue into the future. It depends on continued technological advance and this is by no means certain, as will be argued more fully below. The second problem is both more fundamental and more complex. Diminishing returns from consumption is an intuitively acceptable idea when applied to individual goods and services. Who would argue with the assertion that satisfaction wanes as more pizza, beer or barrels of oil are consumed? It is not so easy to imagine situations where we have so much of all goods that additional quantities of any of them would bring declining satisfaction. Even if such a situation of 'bliss' is possible for a few individuals, it is difficult to conceive of it as applying to entire future populations. However, even if we accept the position that today's generations have a responsibility for the well-being of future generations, we should not conclude that that responsibility should necessarily be met by an artificial inducement to investment in the form of a lower social discount rate. This is because there is a general value judgement accepted by most modern societies that there should be some redistribution of wealth from the rich to the poor. But it is almost certain that technological advances will make our descendants better off than we are. So why should we transfer benefits from today's poor generation to tomorrow's rich generation? The future will be provided for by today's new technology so we need not provide for it through investment.[18] However, continuing technological advance is not guaranteed and, in fact, it has been suggested that increases in knowledge may soon begin to succumb to the law of diminishing returns. For example, we have achieved thirty percent efficiency in the internal combustion engine but the maximum possible efficiency is something less than one hundred percent; thus the potential for improvement is finite. The same point can be applied to recovering petroleum from reservoirs.

This last argument suggests that the problem of provision for the future is perhaps more acute in the case of depletable resources. This is so because the decision to use up a non-renewable resource is irreversible within the relevant time frame of human existence.[19] In such a case, it may be more reasonable to allow for the future to a greater extent, evaluating projects that extend resource availability with a lower social rate of discount. Nor need we look to the end of the resource life to envision benefits from such action. As mentioned above, a major contribution of projects, such as enhanced oil recovery might well be to tide us over a period in the medium term future when conventional sources are running out and adequate substitutes have not yet been developed.

This somewhat extended discussion of the conceptual issues surrounding the choice of a discount rate is intended in part to illustrate the difficulties in analyzing long term capital projects and in part to provide explicit delineation of some factors that should be taken into account by decision makers in society, both government and private. Wrong decisions from a social viewpoint are quite as likely to be due to ignorance of the issues as to deliberate neglect of future generations. If Marglin's schizophrenic man has any basis, it behooves us to educate 'the citizen' since the 'economic man' will instinctively look after himself.

The practical problem of selecting an appropriate discount rate is conditioned by one's view of the theoretical issues outlined above. No consensus has been reached in the literature and examples of studies using discount rates ranging from 0 to 10 percent and higher can be found.[20]

Some guidance is provided by a 1977 study for the Economic Council of Canada that estimated the rate of return to capital in Canada over the period 1965-1974 to be approximately 10 percent.[21] Helliwell et al. approximated the real supply price of capital in the period 1955-1972 at about 5 percent.[22] These considerations led the Treasury Board of Canada to recommend in 1976, a base discount rate for social analysis of 10 percent with rates of 5 and 15 percent for sensitivity analysis.[23] The approach of using several discount rates to evaluate individual projects was incorporated in the present analysis wherein 25 rates ranging from 0 to 100 percent were applied to individual projects.

These rates were easily and inexpensively incorporated into the computer modelling for individual project analysis but the problem of which of the rates to use for purposes of aggregating and reporting results was less tractable. In order to determine aggregate potential for a given discount rate it was necessary to check profitability of each of some 1,536 projects. This was because we evaluated 643 reservoirs, some of which were technically amenable to several different recovery processes. The time and dollar costs of this aspect of the aggregation of the results of individual project evaluations was a deciding factor in our decision to limit reported results to aggregations for three discount rates only.

The preferred discount rate, upon which the bulk of the analysis was based, was 8 percent. This rate was cited as the historical real rate of return for the U.S. Oil Industry in a 1976 study of Enhanced Oil

Recovery by Lewin and Associates.[24] However, there were several other considerations that prompted our adaption of the 8 percent rate. One reason centred on the manner in which risk was eventually incorporated in the analysis. This is discussed more fully in Section 2.2.7, but the essential aspect of our treatment is that risk did not enter solely as a premium in the discount rate. Since there were some other considerations in incorporating risk we felt that a rate somewhat lower than the 10 percent suggested by the Treasury Board would not be out of order.

The precise amount by which the suggested 10 percent rate should be reduced due to the other ways in which risk was being considered was not immediately apparent. Nor did it appear essential that we commit ourselves to some division of our chosen discount rate between risk and pure return to capital. However, we were influenced in this connection by unpublished estimates by Dorfman of a theoretical social rate of discount that lies in the range 3 to 4 1/2 percent.[25] If this is taken as a pure return component of a 10 percent discount rate it implies a risk component of 5 1/2 to 7 percent. Because some aspects of risk are being allowed for in other ways we chose to reduce the suggested rate by 2 percent and to interpret the resulting 8 percent rate as being made up of a 3 percent pure rate of time preference and a 5 percent allowance for risk.

The 8 percent represents a real rate, which abstracts from the rate of inflation. A corresponding nominal rate, if we assume, for example, a 7 percent inflation rate, would be approximately 15 percent. Some support for our choice was accorded by the fact that 15 percent was the basic rate being used for project analysis by two major oil companies, Gulf Canada Ltd. and Imperial Oil Ltd. It was for this reason that we decided to view our 8 percent real rate as an upper bound. Thus we chose to aggregate results and determine potential recoverable reserves based on the 8 percent real discount rate and two smaller rates, 3 percent and 0 percent. The results of this limited sensitivity analysis are presented in Table 5.4. However, it is of some interest to note here that increasing the rate from 0 to 3 percent reduced the number of profitable reservoirs (before taxes) by 4 percent and reduced the amount of recoverable oil by less than one percent. Increasing the discount rate from 3 percent to 8 percent caused a further reduction in profitable reservoirs of about 7 percent and a reduction in recoverable oil of only 6 percent. The results are not very sensitive to changes in the discount rate within a reasonable range.

2.2.3 Investment Criteria

Another problem of cost benefit analysis that requires general treatment is that of determining when projects should be undertaken. On the most general (and most complex) level, this is a question of determining when the welfare of a society is improved by a project. The only truly unambiguous answer to this is one that says, "When no one is made worse off and at least one person is made better off."[26] This is because we have no acceptable basis for making interpersonal comparisons of well being. The degree to which one person in society is made worse off by an action could exceed the combined increase in welfare of the rest of the population.

Unfortunately, almost all of the projects which made no one worse off were used up at the time of creation. Therefore, another criterion was developed which said, "If gainers gain enough to allow them to bribe losers into accepting the project, then welfare is improved."[27] Unfortunately it was soon pointed out that if the losers were actually paid off they might then discover that they would prefer to, and could, bribe the gainers to revert to the initial situation. This seemingly strange result is indeed possible because redistributing income changes peoples' relative valuations of goods and services. But if this was to be the case, in what sense could we say that the project leaves society better off? So another rule was introduced which said that gainers must (hypothetically) be able to bribe losers and once that was (hypothetically) done the losers could not reverse the bribe.[28]

Aside from the distribution question mentioned in footnote 27, which is a major theoretical objection to these criteria, this last refinement seems to put us back into the position of having a criteria so strict its practical applicability will be only rarely possible. An eminently practical escape from this dilemma is put forward by Bergson who suggests simply that choices should be made on the basis of explicit value judgments regarding the desirability of projects.[29] Such judgment would rely on whatever objective information was available but the decision as to whether a project ultimately was good or bad would be an autocratic one by the analyst or government official, or perhaps a corporate officer. The solution is one which in essence sidesteps the problem.

The solution, in practice, is to equate increases in production with increases in welfare so that any specific project is judged to increase welfare when a clear net gain to GNP is demonstrable.[30] This means that procedures for evaluating specfic projects must be considered.

2.2.4 Specific Evaluation Criteria

At the level of deciding among specific investment projects, a number of rules are in use. More common ones include estimating accounting return on investment, pay out times, internal rates of return and net present value. Since the most theoretically desirable rule (NPV) is not the one most commonly used in industry evaluations, some justification for its use here seems in order.

In general, the choice of a decision rule is dependent on both the spectrum of projects under consideration and what it is to be accomplished by the rule in question. The question of the objective of the rules involves distinguishing between decision criteria and performance measures.[31] Performance measures for management control are useful in business. Measures of accounting return on investment which take into account some assumed depreciation of capital equipment in computing profits as a percentage of investment are fairly common. In judging historical performance, such a measure has some validity but as a device to aid in decisions regarding future projects, it fails on two counts. First, the procedure for determining accounting return on investment is somewhat arbitrary, one may compute a return as a percentage of intitial investment or as some average investment cost. Alternate assumptions regarding depreciation can affect the result as well. The second and primary reason is that it ignores differing time patterns of revenues and costs, the time value of money, which was established in the previous section as being a particularly important aspect of rational investment.

The payback period approach, which says choose that investment which will be recovered in the shortest period possible also suffers from failure to incorporate time properly. More important, the payback method ignores potential receipts beyond the date when the investment has been recovered. Justification of this approach as a way for firms to account for risk, early payback presumably suggesting less risk, is not compelling since better ways to handle risk are available.

Turning to those methods that incorporate the discounting process they can be illustrated with the help of Equation 1:

$$4)\quad NPV = \sum_{t=0}^{T} \frac{TR_t - TC_t}{(1 + r)^t}$$

where

NPV = net present value

TR_t = revenue in period t

TC_t = costs in period t

r = rate at which the future is discounted
or
internal rate of return

Given acceptable forecasts of future revenues and costs, if a particular rate of discount is adopted for the analysis the equation can be solved for the net present value. Projects whose value is greater than or equal to 0 would be economically desirable. Alternately, one can solve for the rate that equates costs and benefits (i.e., yields a 0 NPV). This rate is referred to as the internal rate of return and the rule is to undertake all projects where internal rate of return exceeds the firm's opportunity cost of capital (required rate of return).

The interpretation of Equation 1 in these two ways indicates that the approaches are related. However, it should be remembered that they are conceptually distinct and in general the net present value criteria is the more reliable for reasons to be noted below. For the simplest decision either to accept or reject a project, the two rules yield the same signal (i.e., if IRR is greater than r then net present value is greater than 0). But as soon as the decision is complicated by the need to rank projects, which occurs when capital is rationed or when projects are mutually exclusive, the rate of return method remains applicable only when the alternatives are similar in terms of initial cost, project life and patterns of cash flow over time.[32]

When projects differ in one of these dimensions the situation depicted in Figure 2.1 is not unlikely. The IRR and NPV rules conflict for rates less than 10 percent in this example since the $IRR_A > IRR_B$ but clearly the $NPV_B > NPV_A$. The internal rate of return method gives an incorrect ranking as to the worth of the projects because it is assuming that intermediate cash flows can be reinvested at the calculated internal rate of return. But usually the rate at which intermediate cash flows can be reinvested is less than the IRR and so the project is implicitly overvalued.

Another problem concerns the possibility of multiple solutions. For abnormal time patterns of net returns the possibility of more than one rate of return exists. A 'normal' pattern is an initial investment expenditure followed by net inflows to the end of the project. The 'abnormal' case then would involve net outlays late in the project life as when dismantlement is required when it shuts down, or in the case of oil and gas, when capping and plugging a reservoir is required when it is abandoned. The problem is illustrated by Table 2.1 and Figure 2.2. The stream of net revenues changes sign twice so two solutions are possible and, in this case, exist.[33] Neither solution is more correct than the other, thus the occasionally seen advice that the economically relevant solution (i.e., say a positive IRR) should be chosen is theoretically unsound. Although this problem is rare in practice since extreme cases are required to produce mulitple solutions, it happens to be fairly common in the oil industry due to the prevalence of acceleration projects.

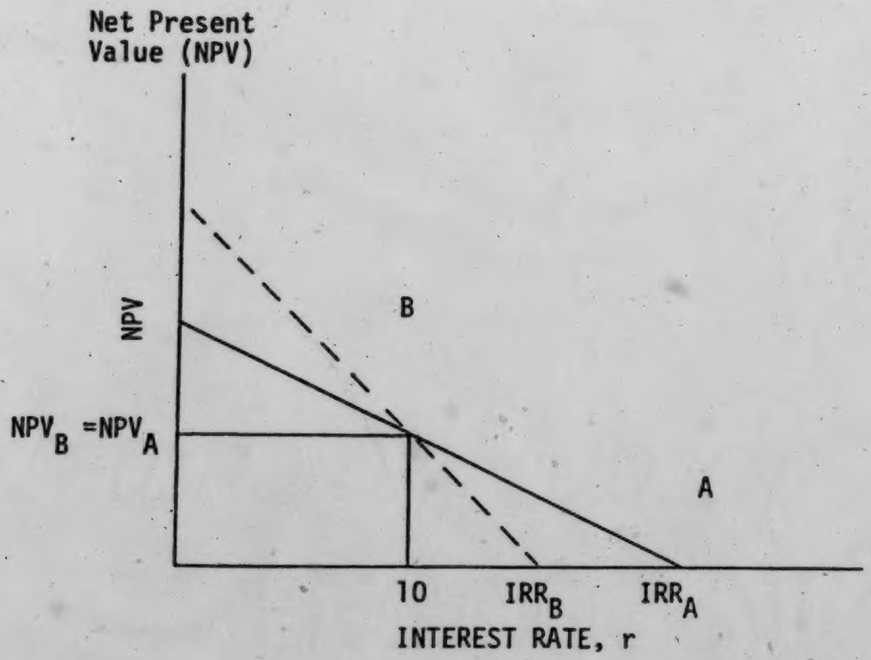


Figure 2.1 - Present Value Profiles Showing the Possible Conflict Between NPV and IRR Rules. IRR_B is less than IRR_A implying A is the preferred project. But for discount rates less than 10 percent, NPV_B is greater than NPV_A implying B is the preferred project.

TABLE 2.1

ABNORMAL EXPENDITURE PROFILE

	Project Year				
r	1	2	3	4	NPV
0	-1	6	-11	6	0
1	-1/2	-6/4	-11/8	6/16	0
2	-1/3	6/9	-11/27	6/81	0
3	-1/4	6/16	-11/64	6/256	

$$NPV = \Sigma \frac{B_t}{(1 + r)^t}$$

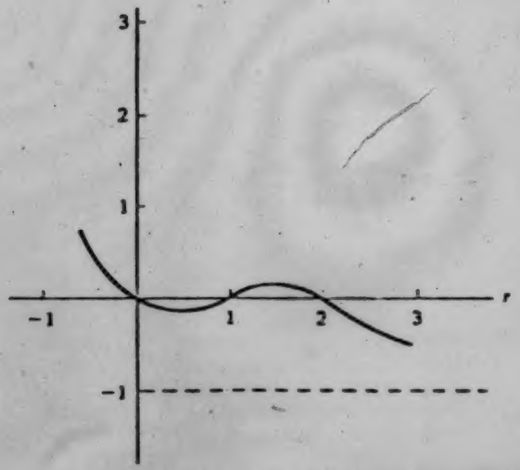


FIGURE 2.2: Abnormal Expenditure Profile

SOURCE: J. Hirshleifer, Investment Interest and Capital, 1970, p. 79, Fig. 3-15.

> An acceleration project is one in which a petroleum or mining company invests funds in order to accelerate the recovery of a given body of oil or minerals. In these situations, the typical cash flow associated with the investment always involve a major reversal of cash flows with the patterns minus plus minus, that is, outlays now produce incremental positive flows in the near future (as recovery is accelerated relative to the status quo) followed by negative incremental flows (as the reserves are exhausted earlier than they would have been if the acceleration investment had not been made). The attempt to measure the IRR for such projects frequently yields multiple and hence meaningless solutions.[34]

In the face of these disadvantages the continued emphasis on IRR methods in the oil industry is to say the least, curious. It is partly explained by the fact that for simple investment decisions, it gives the same signal as NPV rules. It is also in part due to the easier and more intuitive interpretation associated with IRR rules especially for those not familiar with the rationale of discounting. This is, however, hardly a justification for accepting the needless risk of choosing the wrong project. Finally, there may be a reluctance on the part of a manager to undertake investment projects for which the bulk of return occurs far in the future. Such projects adversely affect the accounting measures of profit which are sometimes used to judge the manager's performance. In such cases shareholders' interests in terms of long term value maximization of the firm conflict with managerial performance objectives and the question who runs the firm and to what end becomes relevant. The problem can be mitigated by enhanced communication between managers and investors since most investors are disposed to accept a dip in present returns if future returns promise to be significant.

2.2.5 Inflation

The best way to handle general inflation is to ignore it.[35] This is assuming that the rate of inflation is incorporated in the discount rate used in the analysis. Since interest rates may loosely be considered as the price of money, it is not unreasonable to assume that general inflation would involve increases in this 'price' as well as others. In general, interest rates do increase in inflationary periods to protect lenders from losses in purchasing power on the funds they lend.

We can compare the net present value analysis with and without an inflationary premium to clarify the above point. Thus inflationary increases in net benefits over time are offset by the approximately equal inflationary increases in the rate used to discount these benefits in the calculation of net present value. This is illustrated in Section 4.6.3 below, where we discuss the criteria of economic viability incorporated in the models.

2.2.6 The Future Price of Oil

Price forecasts are fraught with difficulty even when economic factors dominate the price formation process. When political factors are significant, uncertainties quickly reach a level that makes single forecasts more misleading than useful. As one commentator has suggested, the only thing we can be sure of about oil price forecasts is that they will be wrong.[36] Consequently, we will utilize a range of prices which it is hoped will capture the most relevant possibilities. Even so, some consideration of the forces involved is necessary to establish limits to the range.

The real price of oil had been declining slightly over time for a number of years prior to 1973. At that time, OPEC caused a drastic increase (four-fold) in the price of crude, which signalled a new era in the institutional arrangements by which price decisions are made. Clearly, looking to past trends in prices for hints about the future would be a futile exercise since the institutional environment within which prices are determined has been basically altered by the formation of OPEC. However, one can attempt to understand the major underlying causes of the recent changes, combine them with whatever economic and political factors one views as important and structure forecasts accordingly.

A scenario that suggests moderate price increases for the foreseeable future can be built along the following lines. The 1973-1974 price increases may be viewed as a movement from a competitive price level to a monopoly price level. This monopolistic exploitation of world demand is a one-time possibility so there is little likelihood of increases of this magnitude occurring again. This is particularly true given the likelihood of future dominance of OPEC policy by the long-term interests of Saudi Arabia. The price increase has also been accompanied by the development of alternate supplies in the North Sea and Alaska which in the short-run (two or three years) suggests the possibility of a constant or declining real price. But in spite of conservation measures it seems unlikely that demand growth will fall off significantly so we might expect a return to moderately rising real prices in the early 1980s.[37] On logical grounds, a 'most likely' estimate for the rate of increase in real oil prices at this time would be the rate that emerges from the now standard economic model of exploitation of a depleting resource, namely, the market rate of interest.[38]

Although the possibility of a decline in the real price of oil is remote, serious consideration must be given to the possibility of a constant real price, that is, nominal prices keeping pace only with inflation. This could result if world demand growth was stalled due to slower than predicted economic growth or if substitution of other energy sources for oil accelerates. It may also be in the preceived interest of Saudi Arabia. In any case it should be recognized that a 'low' forecast represents an unfavourable development from the point of view of justifying enhanced recovery which to some extent justifies its consideration in a sensitivity analysis.

Subscription to the analysis that justifies our low and medium forecasts should not blind us to the possibility of significant increases in oil prices. For example, consider the case of Iran. With projected population to 2025 triple what it is today (from 40 to 120 million) and with income levels that will imply domestic energy consumption on the scale of Western Europe or even North America, Iran might decide, in 1990, to export only a fraction of what current forecasts show that they could be exporting. They might view national self-sufficiency as important a target as it is currently viewed in the United Sates and Canada.[39] Our high price case will implicitly incorporate this possibility.

Finally, by attaching some probabilities to the various forecasts we could calculate an expected price. This procedure, however, would add little and might even be detrimental since it draws attention away from the variability of the possible outcomes.[40] Instead we carried out the analysis using a range of prices which provide some feeling for how sensitive our results are to changes in this important parameter. We gave some consideration to incorporating a real world price considerably lower than currently prevailing as one of our cases. We decided against it on the basis of current views about the high survival potential of OPEC and a general judgement that even if OPEC should break up, Saudi Arabia would in any event act as a price leader by accommodating its production in the interest of at least maintaining the current world price. This allowed us to run the complete analysis for prices of $15, $20, $25, and (as a limiting case) $100 per barrel oil.

2.2.7 Risk

Risk is either insurable or uninsurable, only the latter requiring specific analytical treatment.[41] All risks are economic in the sense that they ultimately relate to cash flow (or in the social sense, net benefits). However, it is convenient to classify them as technical or economic (according to source rather than effect). In the petroleum industry, technical risks are related to either geology or engineering and economic risks relate to future demand and supply (cost) conditions.

Geological and engineering risks are closely related but may be distinguished because the geological problem is one of establishing the existence and quantity of oil in particular locations whereas the engineering problem is one of how to get at this oil. Both, however, stem from the difficulties of obtaining reliable measurements of rock and fluid parameters and of interpreting such data. The uncertainty inherent in the process is highlighted by Essley, who points out that reservoir engineering is more an art than a science—differing interpretations of data are common. He defines a reservoir engineer as one who

> takes a limited number of facts, adds numerous assumptions, and arrives at an unlimited number of conclusions.[42]

The economic risk is that forecasts of world demand and supply may imply a level of product prices that is not realized in the future. The price may turn out to be lower than expected, reducing the profitability of some enhanced recovery projects that were undertaken because of a higher expected price. Or the price may turn out to be higher than expected, which could mean that some projects that would have been profitable were not undertaken. Given the long lags involved in development operations and the problems of reopening fields once they have been closed down, such projects may be lost forever. Although price is the variable of interest, the forecaster must address demand and supply separately since each depend on different things. Demand forecasts utilize population projections, income growth and a perceived relation between affluence and energy use. Demographic projection techniques are becoming more reliable, as are income projections and our understanding of the relation between GNP and energy use. Future demand uncertainties will arise largely from inability to predict the direction of energy policy and its potential impact. However, even a totally conservation-oriented set of policies with maximum impact in the western countries would only alter world demand growth rates, not eliminate them. This suggests that the significant uncertainties lie on the supply side in the areas of potential new reserves, and in the distributional uncertainties associated with the currently most significant reserves, those of the Middle East.

A number of approaches to incorporating risk into the analytical framework of cost benefit analysis have been put forward. These approaches include arbitrary limitation of a projects's life, use of conservative estimates of net benefits, adding a risk premium to the discount rate, and establishing probability distributions for uncertain variables to explicitly portray the problem for the decision maker. The first two approaches, limited payback periods and conservative estimates, share a common failure. They characterize the risk element in a specific way which may not be the way risk affects any individual project. For example, limiting the payback period implies that returns are certain up to the arbitrary cut-off period whereas in fact, the risk may be actually concentrated in the potential variablibity of returns during the payback period.[43] Other problems are discussed in the noted reference, but in general they arise from failure of the methods to utilize all available information.

Before discussing the last two approaches to risk in project evaluation, it will be useful to consider the manner by which it is handled for general economic activity. The market allows for risk by requiring higher average rates of prospective return as compensation for higher risk levels. This relation is illustrated in Figure 2.3, which illustrates how increasing risks attached to a particular investment will be associated with increases in the required rate of return demanded by lenders. This relation has been established from market data by comparing returns from different classes of securities. Defining risk as potential variability of return, short-term treasury bills may be taken as a risk-free investment, since there is little chance of variation in return and virtually no chance of default. The risk premium required for other types of investments is therefore approximately revealed by the difference between their achieved returns and the return to treasury bills.[44]

This implies that if we use a market rate of interest to discount future values of projects, we have included some allowance for risk. The risk premium in the particular rate chosen may or may not correctly reflect the level of risk in the particular project being evaluated.

A general procedure suggested by this, that is, to incorporate some risk factor in the discount rate, is the most common approach to

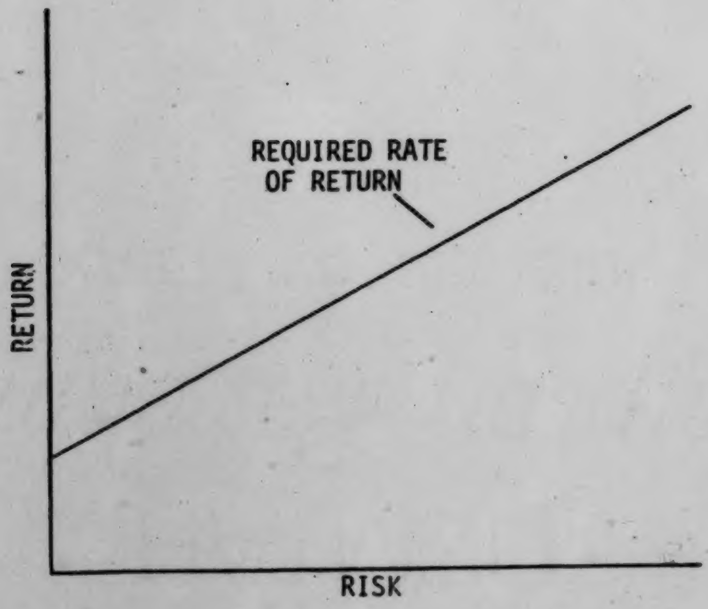


Figure 2.3 - The Relation Between Risk and Required Return in the Market

handling risk in cost benefit analysis. Although we used this approach (among others) there are some conceptual limitations to the procedure that should be recognized. First, it implies that the level of risk is compounded over time which is unlikely to be the case. In our formula for PV_B for instance, it seems we are correcting for a tendency to over-estimate the benefits by larger and larger amounts as time goes on. In actual cases future net benefits sometimes turn out less and sometimes greater than forecasted. The problem is one of variability in returns not consistent and growing over-estimation.[45] This would seem particularly applicable to enhanced recovery projects. Another problem is that risk adjusted discount rates penalize long-term over short-term projects, when in fact the risk element by itself may be the same in both. This is also particularly relevant to enhanced recovery activities which may extend over periods up to twenty years or more.

The final approach to handling risk analytically is the 'probability distribution' approach. This involves assigning probabilities to various values of the uncertain variables and combining the variables in such a way as to produce a range of possible outcomes with associated probabilities. The classical statistical approach to this uses probabilities that are based on observable frequency distributions, which allows recourse to statistical concepts such as the 'law of large numbers'. This assumes we are dealing with repetitive events which, given a large enough number of trials, allows us to objectively define probability in terms of observed relative frequencies. That model may not apply in some situations and, in others, information deficiencies may preclude its use. This would seem to be the case with enhanced recovery projects, since there is very little past experience to draw on. In such cases, the use of subjective probabilities has gained considerable acceptance. They are based on expert opinion supplemented by whatever information may be available. Subjective probabilities may be manipulated mathematically in the same way as objective probabilities which is quite important since it allows determination of single-valued estimates--expected values.[46]

Risk considerations extend beyond the individual project and should be considered from the viewpoint of the firm as a whole and of society. Total risk for the firm may be reduced through diversification which might provide some incentive for firms to engage in enhanced recovery projects depending on the risk characteristics of their whole spectrum of projects. From the social point of view, public project risks are spread over large numbers of individuals through the taxation process. The risk element to any individual is negligible implying that social evaluations should use a risk-free rate.[47] Wilson points out that a relevant consideration is the degree of correlation of project success with national income. Projects likely to pay off when national income is low should be allowed some risk reduction.[48]

These considerations are necessary to an understanding of the limitations of the manner in which risk has been incorporated in our analysis. The probabilistic approach described above has not been sufficiently refined to allow unambiguous application in practice. If our knowledge of the probability distributions of various key parameters used in our study (such as residual saturation after waterflood, residual saturation after tertiary methods, and sweep efficiencies, all of which determine the recovery fraction we expect) was reliable we might use a Monte Carlo approach. This however would require several hundred computer runs per project analysis carried out for close to 1000 projects and the cost would be prohibitive.

Instead we have used more approximate methods in an attempt to make reasonable allowance for this most difficult to quantify notion, risk.

The basic element in our approach involves incorporation of a risk premium in the discount rate. The size of such a premium would presumably vary by project and is essentially a matter of subjective judgement, there being as yet no accepted means by which it can be determined. Our approach, which selected a discount rate that is closely related to the historical return on capital, hopefully captured some average premium that had been incorporated in past projects. As discussed in Section 2.2.3, we decided to explicitly reduce this (unknown) premium by some (subjectively determined) amount, 2 percent, in order to make allowance for the other ways in which risk was explicity considered.

The first of these other ways was an allowance for the possibility of failure at the pilot stage. The evaluation is discussed in detail during the development of the model, Section 4.6.2 below. The result of the evaluation is that 2.2 percent of estimated capital costs are included in the estimate of general and administrative costs for each project, as an explicit allowance against the probability of pilot failure.

The second subsidiary risk element is incorporated in the technical estimation of incremental recovery. The estimate of recoverable oil, discussed in Section 4.3, is reduced in every case by 8 percent to allow for the possibility of less than 100 percent success in actual recovery operations. On an aggregate basis this amounts to a 200 million barrel allowance. In other words, our estimate of 2.4

billion barrels recoverable in Alberta would have been 2.6 billion barrels had this allowance not been incorporate in the models.

A rather approximate indication of the importance of these two measures was obtained by adjusting aggregate revenues and costs and calculating new internal rates of return which could be compared to the base case rate of return. First we reduced capital costs by 2.2 percent to eliminate our previous allowance for the risk of failure of pilot projects. The result was an increase in the (before tax) rate of return from 28.71 percent to 29.05 percent. Then we increased total revenue in each year by 8 percent to eliminate the allowance for error in the technical estimation of recovery. Matching this new revenue stream with the base case stream of costs yielded an internal rate of return of 33.35 percent. Incorporating both of these changes to the revenue and cost stream resulted in a rate of return of 33.72 percent, or approximately a 5 percent increase over the case where the specific allowances for risk were incorporated.

This is only a rough aproximation of the impact our subsidiary measures may have had on the 'risk' component of the discount rate because it involved the same set of reservoirs as emerged in the base case. In practice the increased revenue would bring on stream a number of previously marginal (i.e. high cost) reservoirs and the resulting increment in the rate of return would be somewhat smaller than 5 percent. We therefore felt that reducing the historical rate of return by a conservative 2 percent was appropriate.

Finally, we also carried out a more standard sensitivity analysis to demonstrate how our results would vary with changes in key parameters. The results have been incorporated as an estimate of the range of uncertainty in the presentation of results in Appendix E.

Footnotes

[1] H. Hotelling, "The Economics of Exhaustible Resources." *Journal of Political Economy*, 39 (April 1931), pp. 137-75. A number of studies have elaborated this topic since Hotelling first discussed it. A good nontechnical discussion is contained in Robert M. Solow, "The Economics of Resources or the Resources of Economics." *American Economic Review*, 64 (May 1974), pp. 1014. See also the *Review of Economic Studies Symposium*, 1974 and D. W. Pearce, ed., *The Economics of Natural Resource Depletion*, (London: Macmillan, 1975), pp. 140-176.

[2] An application of the general optimizing theory of exhaustible resources to the oil industry is provided in Robert G. Kuller and Ronald G. Cummings, "An Economic Model of Production and Investment for Petroleum Reservoirs," *American Economic Review*, 64 (March 1974), pp. 66-79. See also N. Smith, "Economics of Production from Natural Resources," *American Economic Review*, 58 (June 1968), pp. 409- 31.

[3] See James W. McKie and Stephen L. McDonald, "Petroleum Conservation in Theory and Practice.", *Quarterly Journal of Economics*, 76 (February 1962), pp. 98-121, for a discussion of this. As noted later in the text, however, the MER is less emphasized by engineers at present because of a growing belief that it is not of great practical significance in most cases.

[4] Under certain assumptions regarding the absence of monopoly elements and the existence of forward and insurance markets, this model meets the pareto criterion of social welfare. It is not our purpose, however, to defend the market as a guide to resource depletion. The discussion is intended primarily to introduce the notion of user costs.

[5] Anthony Scott, "Notes on User Cost", *The Economic Journal*, (June 1953), pp. 368-384. Scott credits Keynes with "inventing" the term in the "Appendix on User Costs," *The General Theory of Employment Interest and Prices*, 1936.

[6] Paul Davidson, "Public Policy Problems of the Domestic Crude Oil Industry", *The American Economic Review*, 53 (March 1963), pp. 85-108.

[7] Scott, "Notes on User Cost," p. 378.

[8] National Petroleum Council, *Enhanced Oil Recovery, EOR: An Analysis of the Potential for Enhanced Oil Recovery From Known Fields in the United States 1976-2000*, H.J. Haynes, Chairman, Committee on Enhanced Recovery Techniques (Washington, D.C.: National Petroleum Council, 1976). Lewin and associates, Inc., *The Potential and Economics of Enhanced Oil Recovery* (Washinton, D.[illegible]., April 1976) prepared for Federal Energy Administration.

[9] The term 'time preference' is used to represent the subjective view of present versus future consumption (the rate at which people would be willing to substitute future consumption for present consumption.)

[10] These four types of rates are not as independent as Exhibit 2.1 might suggest since opportunity cost depends on time preference. However, we assume some literary license in order to make the essential points without needless complication.

[11] There is another source of difference between the social and private opportunity cost of investment. This arises from the effect of investment in increasing the returns to other factor inputs which is a cost from the private viewpoint but a benefit from the social viewpoint. However, this distinction depends on imperfect factor markets and will not be developed here. See N.S. Feldstein,"The Social Preference Discount Rate in Cost-Benefit Analysis," The Economic Journal, 74 (1964), p. 364.

[12] W. J. Baumol, "On the Social Rate of Discount," American Economic Review, 58 (1968), p. 798. Commenting on this paper, Dan Usher establishes that the correct rate is determinate and lies between the opportunity cost rate and the rate of time preference. This is supported by Ramsey, Sandemo, and Dreze who suggest that the actual rate should be determined with some weighted average of the value of the resources taken from consumption and those taken from investment, the weights being the compensated interest derivative of consumption and the interest derivative of investment which would have to be estimated empirically. All of these formulations are based on complicated second best analyses, which makes them difficult to apply in a practical situtation. See Dan Usher and David Ramsey's comment on Baumol's original article in the American Economic Review, 59 (December 1969). The Sandemo and Dreze article, entitled "Discount Rates for Public Investment in Closed and Open Economies," appeared in Economica, 38 (November 1971), pp. 395-312.

[13] Of course, funds may be limited to an individual firm pushing their required return above market rates. Also, the act of raising funds via one financing approach may cause the costs of other funds to rise and this effect should be included in addition to the market rate. Furthermore, the practical matter in the real world as to which of several possible market rates to use must be addressed. While these questions of application are not unimportant, the conceptual framework seems to be correct.

[14] J. Bhagwati, The Economics of Underdeveloped Countries, (New York, Weidenfield and Nicholson, 1966), p. 168.

[15] S. A. Marglin, "The Social Rate of Discount and the Optimal Rate of Investment," Quarterly Journal of Economics, 77 (1963), p. 98.

[16] A. K. Sen, "Isolation, Assurance and the Social Rate of Discount," Quarterly Journal of Economics, 81 (1967), pp. 112-124. The discussion in the text combines two ideas that Sen refers to as the Isolation Paradox and the Assurance Problem.

[17] However, see K.J. Arrow, Social Choice and Individual Values (Wiley, 1951) for a discussion of the failure of the voting process to generate consistent social decisions.

[18] Gordon Tullock, "The Social Rate of Discount and the Optimal Rate of Investment: Comment," Quarterly Journal of Economics, 78 (May 1964), pp. 331-336.

[19] Such a decision may well be made by default due to inadequate knowledge.

[20] W. J. Baumol, "On the Social Rate of Discount," American Economic Review, 58 (September 1968), p. 788. Baumol attributes a 3% estimate to M. S. March in discussion of a paper by Weisbrod in Measuring Benefits of Government Investments, Robert Dorfman ed., 1965. The zero rate is due to H. E. Klarmon, "Syphilis Control Programs," in the same volume. A zero rate is also defended by Talbot Page, Conservation and Economic Efficiency, (Baltimore: Johns Hopkins University Press for Resources For the Future, 1977).

[21] Glenn P. Jenkins, Capital in Canada: Its Social and Private Performance 1965-1974. (Ottawa: Economic Council of Canada October 1977), Discussion paper No. 98.

[22] Helliwell, The Supply Price of Capital in Macroeconomic Models, p. 281 quoted in Planning Branch, Treasury Board Secretariat, (Ottawa: Information Canada), 1976, p.25.

[23] Treasury Board, op. cit.

[24] Lewin and Associates, Inc., The Potential and Economics of Enhanced Oil Recovery, (Washington, D.C.), prepared for Federal Energy Administration, April 1976.

[25] Robert Dorfman, "How to Estimate the Social Rate of Discount," (Unpublished Working Paper, 1975) Dorfman's theoretical development follows K. J. Arrow "Discounting and Public Investment Criteria" in A. V. Kneese and S. C. Smith, eds. Water Research (Baltimore: The John Hopkins Press, 1966), pp.13-32.

[26] This criterion guarantees a "Pareto improvement" named for Vilfredo Pareto, its enunciator.

[27] Credited to Kaldor and Hicks, this is the compensation principle. It ignores the fact that a dollar may mean more to a poor man than to a rich man and thus introduce some bias into the procedure.

[28] This was introduced by Scitovsky and has been referred to as a double compensation criteria.

[29] William J. Baumol, Economic Theory and Operations Analysis, second edition (Englewood Cliffs, New Jersey: Prentice Hall, Inc., 1965), p. 380.

[30] The inadequacy of GNP as a measure of social welfare is, however, widely accepted even in introductory economics textbooks. But it does have some usefulness in that one can say something about whether changes in GNP are good or bad according to whether or not benefits of the change exceed costs, where costs are defined to include all social and environmental effects.

[31] Ezra Solomon and John J. Pringle, An Introduction to Financial Management, (Santa Monica, Goodyear, 1977), p. 256.

[32] E. J. Mishan provides a procedure in which projects differing in one or more of these aspects can be made comparable for evaluation purposes. See E. J. Mishan, Cost Benefit Analysis, (Lonbon, Allen and Unwin, 1975), chaps. 6 to 8.

[33] In fact more solutions are possible. According to Descartes rule of signs, the number of solutions is at most equal to the number of reversals of sign in the cash flow stream. It is also possible that a project has no solutions, which would occur if the equation had only imaginary roots.

[34] Ezra Solomon and John J. Pringle, An Introduction to Financial Management, p. 269. The possibility was first noted by James H. Lorie and Leonard J. Savage in "Three Problems in Rationing Capital," Journal of Business, 28 (October 1955), pp. 220-223.

[35] This assumes an economy not engaging in foreign trade which is a reasonable assumption for purposes of the point being made. Actual project evaluations where the project involves imports or exports would have to incorporate any differences in general inflation between trading countries.

[36] A. P. H. Van Meurs, "Energy Pricing Trends Until 1990," comments at the Conference on Energy Conservation, Energy Conservation Makes Dollars and Sense, (Toronto 1977), Canadian Pulp and Paper Association.

[37] The continuing perversity of American energy policy reinforces this belief. See Edward W. Erickson and Leonard Waverman, editors, The Energy Question: An International Failure of Policy, vol. 1, Introduction, for some thoughts on the influence of policy decisions on the energy stituation.

[38] H. Hotelling, "The Economics of Exhaustible Resources."

[39] A. P. H. Van Meurs, "Energy Pricing Trends Until 1990."

[40] The procedure is suggested by G. C. Benelli, "Forecasting Profitability of Oil-exploration Projects," Bull. Association Petroleum Geologists, 51 (11), 2228-2245.

[41] Risk and uncertainty have been distinguished but this distinction adds little to our discussion and has been ignored. See F. H. Knight, Risk, Uncertainty and Profit, New York, 1921.

[42] P. C. Essley, "What is Reservoir Engineering?" Journal of Petroleum Technology, January 1965, pp. 20-21, quoted in M. A. Adelman, The World Petroleum Market, (RFF 1972), p. 55.

[43] Weingartner defends the payback period approach in cases where project life is the most significant source of uncertainty. H. H. Weingartner, "Some New Thoughts on the Payback Period and Capital Budgeting Decisions," in Byrne, et al eds. Studies in Budgeting, (Amsterdam: North Holland, 1971). However, Bromwich points out that even here risk reduction depends on how the funds returned by any project are used. For discussion of these issues see Michael Bromwich, The Economics of Capital Budgeting, (Middlesex, Pengiun, 1976), chap. 12.

[44] I. Friend and M. Blume, "The Demand for Risky Assets," American Economic Review, December 1975. R. Ibbotsen and R. Senquefield, "Stocks, Bonds, Bills and Inflation: Year-by-Year Historical Returns 1926-1974," Journal of Business, January 1976. G. David Quirin and Basil A. Kalyman, "The Financial Position of the Petroleum Industry," Campbell Watkins and Michael Walker eds. Oil in the Seventies, (Vancouver, The Fraser Institute, 1977).

[45] An exception to this is discussed in Ajit K. Dasgupta and D. W. Pearce, Cost-Benefit Analysis, (London, MacMillan 1972), p. 195. This occurs when the only risk is that the project may fail at any time.

[46] The statement is somewhat strong since there is some controversy on this point. See H. E. Kyburg, Jr., and H. E. Smokler eds. Studies in Subjective Probability, 1964. A brief discussion also appears in Dasgupta and Pearce, pp. 180-185.

[47] K. J. Arrow and R. Lind, "Uncertainty and the Evaluation of Public Investment Decisions," American Economic Review, 60 (June 1970), pp. 364-378.

[48] Robert Wilson, Risk Measurement of Public Projects, Technical Report No. 240, (California Institute for Mathematical Studies in Social Sciences, 1977).

CHAPTER 3

RESERVOIR DESCRIPTION, ENGINEERING, AND FUNDAMENTALS OF ENHANCED RECOVERY PROCESSES

3.1 Introduction

A typical reservoir is shown in Figure 3.1[1] It is bounded above and below by impervious rock whereas the reservoir rock is porous and over many years, oil, water, and gas have accumulated in the porous reservoir layer. Porosity is the percentage of void or empty space in a rock formation and it depends on the shape and arrangement of the rock grains. Grain size is not important but variation in size is. Porosities can range from 0 (granite) to 48 (some sandstones), these percentages being a measure of the storage capacity of a particular volume of rock. The pore spaces may be connected or isolated but only the first case will allow fluid flow and is therefore referred to as 'effective porosity'.

The ease with which a fluid can move through interconnected pore spaces is called permeability. It depends on the size of the pores and the amount of cementing material between the grains. It would seem logical that the larger the porosity the larger would be the permeability and this is often, but not always, the case. Many porous rocks such as clay and shale have no permeability at all.

The distribution of the fluid within the reservoir is determined by wettability characteristics of the rock-fluid combination and by capillary pressures.[2] Wettability has to do with the tendency of particles to cling together and may be recalled from high school experimentation with glass rods placed alternately in water and mercury

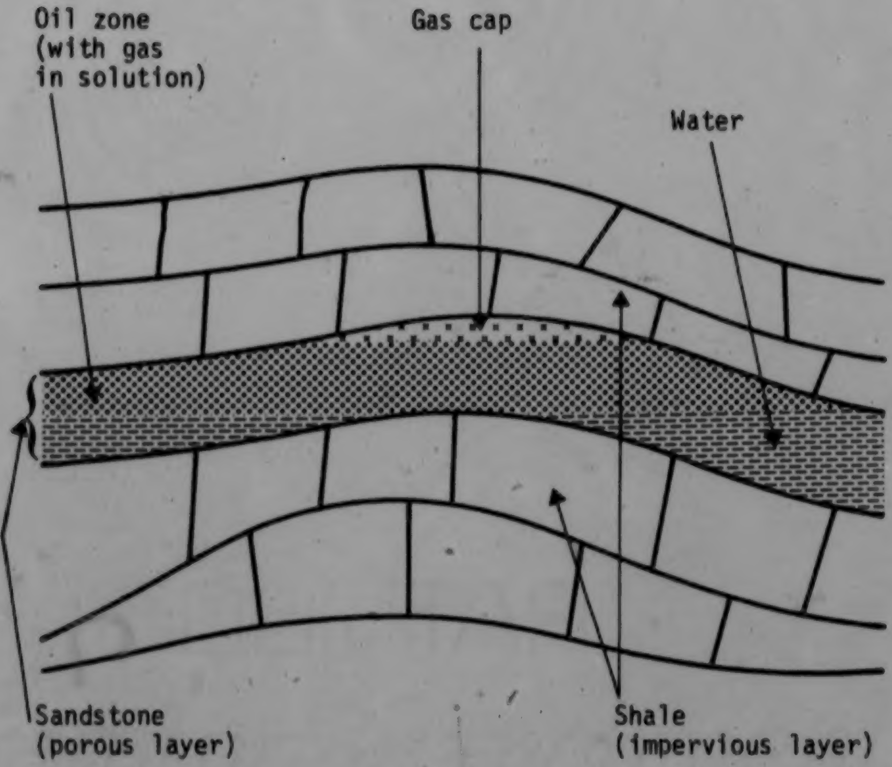


Figure 3.1 - An Oil Reservoir.

solutions. Water adheres to the rod whereas mercury does not. Likewise, in many reservoirs the rock 'prefers' to be wetted by water (water wet reservoirs) whereas in others the preference is for oil (oil wet reservoirs). This will affect the manner in which the oil is displaced in production and the problems which cause some of the oil to be left behind.

Capillary attraction may also be recalled as the cause of water rising in a capillary tube placed in a container of water.[3] The water surface is also convex due to surface tension, the energy required to maintain the interface between the air and the water. In a case where contact is between two liquids, we use the term interfacial tension instead of surface tension. So in a pore filled with oil and water there is some capillary pressure caused by this interfacial tension which must somehow be overcome if we are to move the drops of oil out of the pore spaces. The effect of these things on the distribution of the fluid in the reservoir may be imagined by considering a bottle with water in a layer at the bottom, oil in the next layer and gas in the top layer.[4] If we now fill the bottle with sand, shake it up and let it settle, we would be creating capillary spaces just as they exist in a reservoir and the tension and density differences would cause an uneven distribution to develop, though the general layering effect would reappear. Near the bottom of the bottle, the pore spaces would be filled with 100 percent water but this percentage would decline as we went up toward the oil zone until finally we would reach some point at which there was minimum water saturation caused by the water forming a thin film around each grain of sand. This is called 'interstitial' or 'connate' water and the range over which we move from 100 percent water to the irreducible minimum amount of water is called the transition zone (water-oil contact).[5] There is a similar transition zone between oil and gas (gas-oil contact).

Now imagine holding the sand in place and trying to pour out fluids. One can imagine they will not pour very well, primarily because of the capillary pressure. But the pour rate or flow rate will also depend on characteristics of the fluids, mainly the gravity and viscosity. Gravity is a measure of density of the fluid and viscosity is a fluid property which determines how easily a fluid flows. The higher the viscosity the lower is the flow rate (honey has a higher viscosity than water). Since the precise composition of oil differs in different areas both viscosity and gravity differ as well.

Oil flow results from a complex interaction of a number of forces: fluid and rock expansion, gravity drainage, capillary expulsion and fluid displacement.[6] Oil, water and even rock are slightly compressible and, given the depth and area over which they occur relative to a reservoir, the expansion force is not insignificant. Capillary forces are activated when a well is drilled setting up a pressure differential in the reservoir. The fluids flow toward the low pressure area around the well bore (the pressure sink) in an attempt to regain an equilibrium. The pressure drop also allows the expansion of gas which may be either dissolved in the oil or trapped as a cap above the oil. This gas 'displaces' the oil toward the well bore. This displacement effect also occurs, with even greater effectiveness, when water from an adjacent water leg (aquifer) expands into the oil zone. One or all of the mechanisms may be operating in any reservoir, but usually one predominates. Reservoirs are, therefore, categorized as to their principal drive mechanisms which may be 'dissolved gas drive', 'gas cap drive', or 'water drive'.

3.1.1 Dissolved Gas Drive
(Depletion Drive)

Oil is composed of hundred of hydrocarbons, light, medium and heavy. The light hydrocarbons normally exist in the gaseous phase, but under sufficient pressure they will remain in liquid solution with the heavier hydrocarbons. When production begins, the pressure drops and the gas is liberated from solution whereupon it expands in volume considerably and assists in displacing the remaining liquid toward the well bore. The pressure drop continues as production proceeds and eventually the energy available from the expanding gas is depleted to the point where it will not assist the oil to the surface and some artificial lift mechanism (pump) is required. Eventually the energy is depleted to the point where it will not even cause fluid flow within the reservoir. This usually happens relatively quickly which means there is a low recovery at the primary stage of production (5 to 25 percent). These low productivity reservoirs are good candidates for enhanced recovery techniques since they usually have a high percentage of oil left in place.

3.1.2 Gas Cap Drive

Although oil will accept infinite amounts of gas in solution if the temperature and pressure are adequate, some reservoirs are found to have free gas which has collected in the porous medium above the oil. The pressure is insufficient to hold all the lights in solution. In this case, further reduction in pressure caused by a producing well has two consequences: it allows the gas cap to expand displacing the oil toward the well, and it allows more gas to come out of solution providing further impetus to the transportation process. Because of the gas cap expansion, the pressure decline in the reservoir occurs more slowly than it does in the case of dissolved gas drive which means that ultimate recovery is often quite a bit higher (20 to 40 percent). This, of course, depends on a number of factors. The size of the gas cap is probably the most important but the effectiveness of the other forces which may be operating, such as gravity drainage or capillary action, may be significant in individual cases.

3.1.3 Water Drive

The most productive reservoirs, at the primary stage of production, are those in which the principal transporting force is displacement by water from an adjoining water source (aquifer). As hydrocarbons are extracted through production, displacement is effected by expansion of the water, compression of the aquifer rock, and artesian flow if the aquifer level happens to be above the oil.

This process involves a decline in pressure similar to the depletion gas drive case when the adjoining aquifer is not large relative to the reservoir and is not being replenished by surface water. But in many cases the aquifer is very much larger than the reservoir, or it outcrops in some area allowing it to be constantly replenished. Then reservoir energy lasts much longer. Even in this case, however, some pressure decline will occur since the displacing water must travel from further and further away as production proceeds. But this can be mitigated by avoiding excessive production rates and the result is in general that recovery from this type of reservoir is higher than for gas cap or dissolved gas drive reservoirs.

3.1.4 Combination Drive

Usually reservoirs are driven by a combination of the above forces which makes the optimal production procedure quite complicated.

3.2 Problems of Production

The production problems faced by a reservoir engineer are varied and complex. Our discussion will be limited to those that are significant to enhanced recovery. These have to do with pressure, production of water and production of gas.

Most of the pressure drop in a reservoir occurs quite close to the well bore (within fifteen feet) and so the area around the well bore is referred to as a pressure sink. The naturally lower pressure around the well bore may be reduced even further by damage to the permeability of the medium around the well bore caused by drilling. The potential significance of this is illustrated by a comparison of production rates with and without a damaged zone around the well. For a fairly standard set of parameters, damage reducing permeability (for a five foot radius around a well) from 150 millidarcies to 15 millidarcies results in a drop in production from 126 barrels per day to 32 barrels per day.[7] The condition can usually be treated if its cause can be diagnosed, but since there are several possible causes, treatment is sometimes a trial and error process. The use of injected acids or hydraulic fracturing are fairly common solutions and are sometimes also used to increase permeability in areas where it is naturally low.

The other major problem involves the production of unwanted materials such as water and gas. This occurs when these displacing materials break through the bank of oil they are displacing (just as your finger might break through a ball of jelly it was pushing) or when the pressure drop around the well bore pulls the gas in the cap down to the completed area of the well or pulls the water up toward the completed area. This latter effect is referred to as 'coning'. The former effect is called 'fingering' and is due to differing permeabilities in the various strata and differing viscosities of displacing versus displaced fluid. Both the oil and the displacing fluid travel more quickly through the strata of high permeability and breakthrough at the well bore may occur well before the oil has proceeded very far along the other strata. Or the higher viscosity oil may prefer to absorb to the rock surface allowing the water to move ahead. Once this occurs, a path has been broken, so to speak, which the remaining displacing fluid will prefer to follow. The ratio in production of displacing fluid or gas to oil may become so great as to make further production uneconomic because of separation or disposal costs. Or the displacing fluid may bypass entire segments of oil bearing rock.

3.3 Economic Problems of Production

3.3.1 Oil - A Fugitive Resource

A production problem that has received much attention in the economic literature occurs when oil reservoirs extend over two or more surface leases. This is sometimes exacerbated by the checkerboard fashion in which leases are commonly distributed in Alberta. When a reservoir is developed by two or more different operators there is a strong incentive for production rates to be as high as possible since ownership of the oil is only established by capturing it through production.

It was once widely held that production rates could be so high that ultimate recovery would be adversely affected because of pressure losses. This problem is not emphasized today since many engineers feel ultimate recovery is independent of production rate at the primary stage of development. However, this opinion is not universally accepted and rates may be important in certain cases such as high relief reservoirs where gravity drainage is an important part of the drive process. The problem is important from the economic viewpoint, however, since the incentive toward higher rates may result in a higher than optimum density of wells as operators compete to get the oil out of the ground.

Another problem occurs in secondary production when waterflooding drives a bank of oil toward producing wells and much oil could be driven within the influence of the well of a competitor. This could reduce the incentive to maximize recovery. These problems have led to the practice of voluntary unitization of reservoirs, wherein the development is operated for optimal recovery and the oil is divided among the operators based on the proportion of the surface area they control.[8] Unitization could be compulsory according to conservation regulations in Alberta, but it has never been necessary to impose such an agreement.

3.3.2 Production Rates

The problem of production rates versus ultimate recovey is critical to EOR evaluation since, other things equal, the present value of the revenue stream is increased when production is shifted towards the present. If high production rates reduce ultimate recovery, this trade-off must be resolved even in one-owner fields. As discussed in the previous section, the problem is only occasionally relevant in primary production and, as it turns out, the evidence indicates a similar situation exists in enhanced recovery operations. Waterflooding rates have been shown not to affect recovery at the economic limit, the point at which production is no longer economic.[9] In the case of surfactant floods, higher production rates actually increase ultimate recovery because of the mechanisms involved. But the solvent flood case does have rate dependent characteristics. The effect of production rates on recovery are discussed in more detail under each process.

3.4 Enhanced Recovery

We are now in a position to consider the production process of direct interest to this study, that of enhanced recovery. The particular process varies according to the characteristics of the particular reservoir under consideration. That is, each reservoir must be considered as a unique case. Some grouping is possible according to which general approach to enhanced recovery is adopted. But first some terminological matters must be clarified. There is general agreement that 'primary production' refers to production utilizing the natural reservoir energy. That is, the pressure differential is sufficient to cause oil to flow to the wellhead and to the surface. Even if pumping is required to bring it to the surface it is considered as primary production.

Terminology for other stages of production is not universally accepted. The broadest definition of 'Enhanced Recovery' includes any oil production via artificial supplementation of natural reservoir energy.[10] Traditionally, however, the terms, secondary and tertiary recovery, have been widely used. 'Secondary recovery' normally refers to the injection of gas or water into a reservoir to either maintain the pressure or to act as an external displacing agent. The term came into general use because such operations invariably were the second stage of field development. The term, 'tertiary recovery', was quite naturally adopted to refer to methods that might be applied at the third stage (after gas or waterflood) to dislodge and produce yet further quantities of oil. These terms are now inadequate descriptors since the 'timing' aspect depends on the particular case. A so-called tertiary process may well be initiated at the primary stage of production in an optimal situation. Because of the unfamiliarity of some of the tertiary processes (i.e., chemical injection, steamflooding, fire flooding, etc.) the term 'exotic' gained some acceptance for a while. But as the processes became more familiar, this term also became somewhat unsatisfactory and is falling from general use. For example, steam stimulation is so widely practiced in California that it is considered as a standard production process and in one major estimation of enhanced recovery potential in the U.S., steam stimulation was not even considered, being judged a secondary technique. In this report we follow the National Petroleum Council in defining enhanced recovery as

> ...the additional recovery of oil from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods.[11]

We also use the term 'tertiary recovery' since it is still widely accepted in industry. Both terms explicitly exclude pressure maintenance and waterflooding schemes but include all others. However the fortunes of any enhanced recovery operation will be intimately bound up with the results of waterflooding so the discussion of the various processes must begin at this 'secondary' stage.

3.4.1 Aspects of Waterflooding

It is an interesting fact of life, long used as an example in introducing students of economics to value theory, that water, essential to all life forms, is nonetheless relatively inexpensive. The explanation, of course, lies in its extensive availability in usable form. This makes it a rather desirable input in oil production as well and accounts, in part, for the fact that waterflooding is at present an almost automatic second step in reservoir development.[12] Pressure maintenance schemes use water injection in low permeability reservoirs to prevent pressure from declining too far, thereby causing a slowdown in the flow rate in the reservoir. A side benefit of maintaining pressure is that it prevents gas from coming out of solution and this dissolved gas keeps the viscosity of the gas-oil fluid low.

Ultimately the primary drive energy is depleted and waterflooding is instituted as a direct displacement process to continue production. This is accomplished by drilling injection wells through which water is injected to the reservoir and travels toward producing wells. Oil and water do not mix so the injected water acts to displace some of the remaining oil from the pores forming an oil bank which is pushed in front of the invading water toward the producing well. Production will increase as the oil bank enters the producing well area but eventually the displacing water will also 'break through' to the producing well and production will thereafter involve increasing amounts of water per barrel of oil produced. Eventually the costs of lifting and disposing of the produced water make further production uneconomic and the well is abandoned. At what point production becomes uneconomic depends on the costs of providing and disposing of the water and this varies by location. In some instances production ratios of 100 barrels of water or more per barrel of oil are maintained for significant periods. The following discussion of factors influencing the effectiveness of waterflooding as a recovery technique is intended as an introduction to the factors relevant to enhanced oil recovery schemes in general.

$$E_R = E_A \times E_V \times E_D$$

where

E_R is recovery efficiency, the proportion of oil in place at the beginning of the waterflood that is recovered.

E_A is areal sweep efficiency, the fraction of the reservoir area contacted by water.

E_V is vertical sweep efficiency, the fraction of the vertical extent of the reservoir contacted by water.

E_D is displacement efficiency, the proportion of the oil in the contacted segment of the reservoir which is displaced.

The equation is generally applicable to all the fluid injection methods of enhanced recovery processes and so a brief discussion of the principal determinants of each of the factors will be helpful.

Areal Sweep Efficiency

This is determined by the well pattern, the injected volume, the mobility ratio, and other factors.[13]

The mobility of a fluid in a porous medium is a measure of the ease with which that particular fluid moves through that particular formation. It is defined as the permeability to that fluid divided by the fluid visocisty.

$$\text{Mobility} = \frac{\text{Permeability}}{\text{Viscosity}}$$

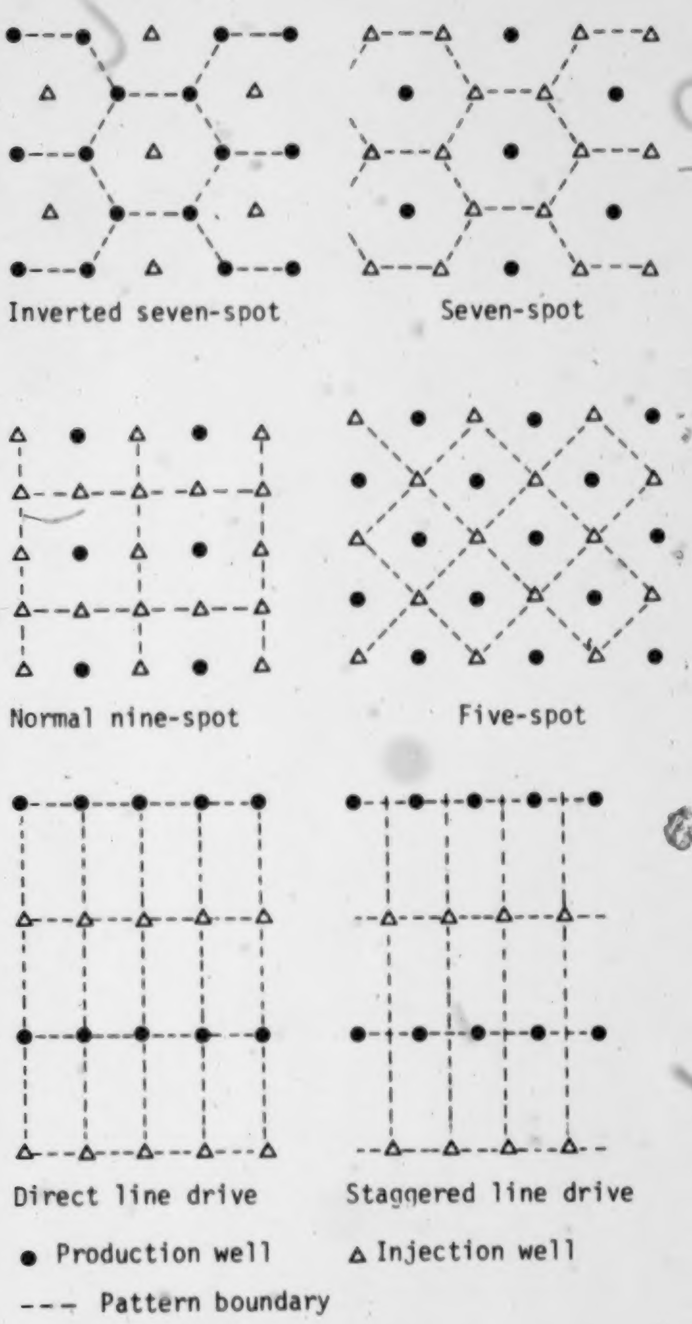
Clearly, high viscosity oil is less mobile than low viscosity oil and oil of any viscosity will be more mobile the higher the permeability.

The term mobility 'ratio' refers to the mobility of the displacing fluid (usually water) divided by the mobility of the displaced fluid (usually oil).

$$\text{Mobility ratio} = \frac{\text{Mobility}_{\text{water}}}{\text{Mobility}_{\text{oil}}} = \frac{\text{Permeability}_w/\text{Viscosity}_w}{\text{Permeability}_o/\text{Viscosity}_o}$$

A low mobility ratio (≤ 1) is desirable to ensure that the displacing fluid can effectively spread out in the formation and gradually displace an oil bank toward the producing well. A high mobility ratio, meaning the water is able to move easier than the oil, would probably mean that the water would bypass the oil, developing preferred paths of travel, thus reducing the area swept. One objective of the polymer flood process, as will be seen, is to lower the mobility ratio by increasing the viscosity of the injected water.

The fact that larger volumes of injected fluid probably lead to greater areal sweep efficiencies needs little comment but the effect of the flooding pattern should be illustrated. Figure 3.2 shows a number of patterns of well placement, the choice of which would depend on the particular reservoir. By convention, flood patterns are identified by the number of injectors that surround a producer. Figure 3.3 illustrates the most common pattern, the five spot, in which four producers surround the injector (with many adjacent five spots in an actual development, the number of producers and injectors is approximately equal). The solid lines in the figure enclose the area that might be swept. Breakthrough at producing wells increases the pressure differential at the corner points resulting in the centre area being partially bypassed. The dotted lines indicate what the sweep efficiency might be if the mobility ratio were somehow reduced. The average sweep efficiency at breakthrough for a five spot pattern is approximately 72 percent but this improves with further injection until at the economic limit the sweep efficiency is often close to 100 percent.[14]


Inverted seven-spot

Seven-spot

Normal nine-spot

Five-spot

Direct line drive

Staggered line drive

Figure 3.2 - Flooding Patterns.

SOURCE: Interstate Oil Compact Commission, Secondary and Tertiary Oil Recovery Processes, 1974 pp. 14-16.

Vertical Sweep Efficiency

Figure 3.4 illustrates the problem caused by layers of differing permeability which alter mobility ratios and cause the injected fluid to move through the reservoir as an irregular front. Breakthrough to the well may occur causing segments of the reservoir to be bypassed completely.

Displacement Efficiency

This is a microscopic concept referring to the proportion of the oil actually contacted by water and displaced or flushed out of its pore space. The remaining oil is called the residual oil saturation. In water wet reservoirs it occurs as droplets of oil trapped by interfacial forces between oil and water. Once these droplets form and are surrounded by water they are difficult to move and end up trapped in the pore channels. In oil wet reservoirs the residual oil remains as a thin film on the reservoir rock. The two cases require different approaches at the enhanced recovery stage.

Total Recovery Efficiency

The recovery efficiency is therefore determined by the above three factors, each of which has its own determinants. An important point to remember is that the unrecovered oil is of two types:

1. oil in non-contacted segments of the reservoir
2. residual oil remaining behind after the advancement of the displacing fluid.

We are now almost prepared to discuss the various techniques that fall under our definition of enhanced recovery. One further technical relation will facilitate the explanation. This is the simplified characterization of fluid flow through a porous medium. Fluid flow will occur if there are pressure differences in the medium such as

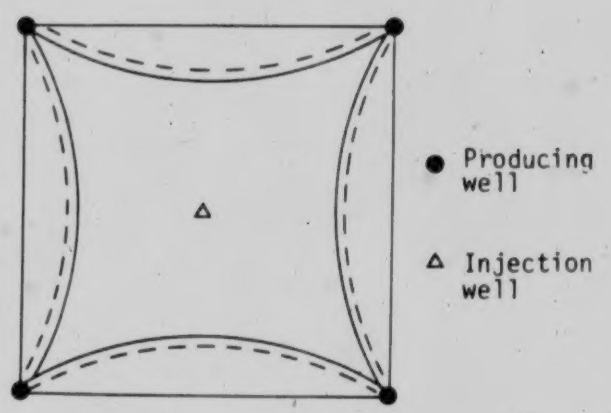


Figure 3.3 - Dashed Lines Indicate the Potential Increase in Areal Sweep Efficiency from a Reduction in Mobility Ratios.

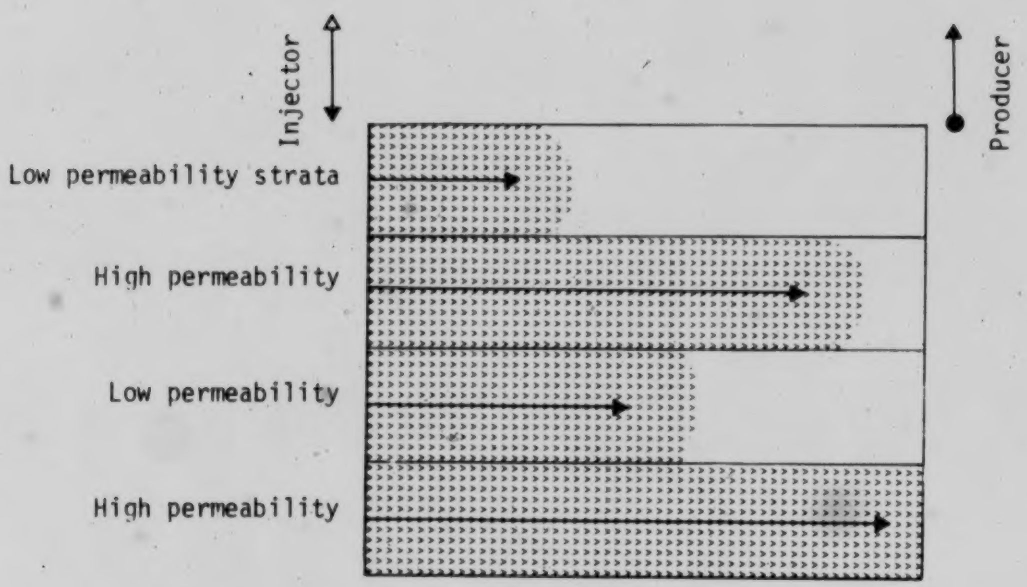


Figure 3.4 - Fluid in Lower High Permeability Zone has Reached the Producer. Injected Water Will Tend to Follow This 'Broken Path' and the Top Layer May never be Swept.

are created when a well is drilled into a reservoir.[15] According to a relationship called Darcy's Law, the rate of flow is directly proportional to permeability, area and the pressure differential, and it is inversely proportional to the viscosity of the fluid and the length of the medium.[16]

$$\text{Flow rate} = \frac{(\text{permeability})(\text{area})(\text{pressure})}{(\text{viscosity})(\text{length})}$$

A major objective of enhanced recovery will be to maximize flow rates by altering the value of certain parameters that affect the rates of flow.

3.5 Enhanced Oil Recovery Technical Overview

Oil reservoirs are volumes of porous rock holding water, oil and gas under pressure. Primary production is accomplished by displacement of the oil toward producing wells by the water and/or gas, sometimes assisted by gravity forces. Unless the produced oil is replaced from an adjacent aquifer, pressure decline occurs, reducing the driving force and liberating gas bubbles which may impede the oil flow. Since some reservoirs are not pressure maintained by natural means (aquifers or gas caps), some artificial means of preventing pressure decline is required. Injection of gas or water sometimes accomplishes this 'pressure maintenance'. Eventually, however, natural reservoir energy is depleted and secondary recovery techniques are implemented. These also involve fluid injection which affects pressure and, at this stage, is also effective for displacing oil directly. When the procedure has reached its economic limit there is still a considerable amount of oil left in the reservoir, roughly two-thirds of the original oil in place.

This residual oil, the target for enhanced recovery operations, exists in regions of two types, those that were contacted by the displacing fluid in the secondary phase and those that were not — that remain in original reservoir conditions. In regions of the first type the oil left behind is usually in the form of droplets trapped in pore spaces by the displacing fluid although it sometimes exists as a thin film on the rock surface. Enhanced recovery operations have two general objectives:

1. to increase the displacement efficiency either by reducing the forces (i.e., interfacial tension) that cause the trapping of droplets of oil, or by increasing the oil's escape potential by increasing the pressure gradients in pores or increasing the solution effects encouraging vapourization or solubilization; and
2. to increase the contacted portion of the reservoir (i.e., increase sweep efficiency) by affecting mobility ratios or interfering with the natural flow paths that would be followed by injected fluids, thus forcing them to 'break new trails' through the reservoir.

Since enhanced recovery techniques will normally follow a waterflood operation, it is important to know how the waterflood performed. Although a successful waterflood operation is encouraging since it implies injected fluids will contact most of the reservoir, the waterflood itself may adversely affect enhanced recovery potential by reducing residual oil saturations below optimum levels. This is why increasing consideration is being given to earlier implementation of these (formerly) 'tertiary' techniques. In come cases they may be initiated at the primary production stage.

The specific processes discussed in this summary are shown in Exhibit 3.1.

EXHIBIT 3.1

ENHANCED RECOVERY PROCESSES

Polymer

- Mobility Control
- Diverting and Blocking

Surfactant

- Microemulsion

Alkaline

- Emulsification and Entrainment
- Emulsification and Entrapment
- Wettability Reversal — Oil to Water
- Wettability Reversal — Water to Oil

Hydrocarbon Miscible

Carbon Dioxide

- Miscible
- Immiscible

Thermal

- Cyclic Steam Injection
- Steam Drive
- Hot Water
- Forward Dry Combustion
- Forward Wet Combustion
- Reverse Combustion

3.5.1 Polymer Flooding

Polymer floods are waterfloods that have been treated with a suitable polymer, thereby increasing the viscosity of the water. The exact manner by which recovery is increased is not completely understood but three possible effects have been identified, all of them related to sweep efficiency rather than displacement efficiency. That is, the flood does not reduce ultimate residual oil in the contacted zone beyond that achieved by waterflood, but it comes in contact with more oil. It may also reduce the amount of water required to achieve a given residual saturation. The first and probably most important mechanism is the reduction in mobility ratio. Polymers used in oil recovery are high molecular weight water soluble chemicals. Their addition to water increases its viscosity, reducing its mobility, thereby reducing the oil-water mobility ratio.

With some polymers, the mobility ratio may also be affected by reduction of the permeability of the formation to water. This occurs when the polymer is adsorbed or retained on the rock surface. This seems to make it harder for water to flow but has little effect on oil. Therefore, once a polymer flood has worked its way through the reservoir, subsequent waterfloods exhibit a lower mobility ratio. These mechanisms are important when the reservoir oil is highly viscous, implying an adverse initial mobility ratio.

Another mechanism by which polymer addition works is through diversion of oil from high permeability to low permeability strata. This allows a more even advance of the flood front through the reservoir and may prevent bypassing of some low permeability segments. The diversion is accomplished by injecting a polymer solution with gelling capability into the high permeability zones. When the gel 'sets' the zones are blocked and subsequently injected water is diverted to lower permeability zones.

The amount of polymer required depends on the objective, with relatively large amounts being used for mobility control and small slugs when sweep pattern improvement is sought through reaction with the reservoir rock.

Polymers primarily used in the field to date are poly- acrylamides (synthetic) and polysaccharides (biologically produced). The performance of the former is adversely affected by salinity, divalent ion concentration and shearing (injection stress). Therefore, relatively fresh water and injection rates moderate enough to ensure the polymer slug is not adversely affected by insertion stress are required, which affects the economics of the process. Polysaccharides are less affected by these problems but both are subject to attack by bacteria and are difficult to get into solution when supplied in dry powder form. Currently polysaccharides are more expensive and have undergone much less field testing than their synthetic cousin.

Laboratory studies cited by Sandiford have shown polymer mobility control can double waterflood recovery but field applications have provided incremental production over waterflood of from 5 to 15 percent. Failures are now thought to be due to inadequate slug size and low concentrations suggesting that future applications will have to use more polymer than before.[17]

3.5.2 Surfactant Flooding

Surfactants, literally surface active agents, act much like washing detergents cutting grease from clothes when they remove oil from reservoir rock. The mechanism is a reduction in interfacial tension between the oil and the displacing fluid reducing capillary forces and liberating more oil. The process emphasizes increasing displacement efficiency rather than sweep efficiencies. The major problem has been adsorption of the chemicals, usually petroleum sulphonate, by the reservoir rock.

Microemulsion Flooding

This is also known as micellar or soluble oil flooding. Essentially it involves injection of a micellar solution slug followed by a polymer buffer which is driven by a regular waterflood. The micellar solution achieves forward displacement of a bank of oil and water which itself collects more oil as it moves, while the polymer acts as a buffer to protect the slug from being broken up by the following water drive. The micellar composition varies according to circumstances, but usually contains a surfactant, some hydrocarbon source which varies from LPG to lease crude, a co-surfactant (alcohol) and sometimes salts, which increase the viscosity of the solution thus improving the mobility ratio. Two quite different approaches to the use of microemulsions in enhanced recovery have emerged, low concentration solutions versus high concentration solutions.[18]

The low concentration approach involves injection of a relatively large amount (15 to 60 percent pore volume) of a low concentration surfactant which acts to reduce interfacial tensions. This increases displacement efficiency but does not clean out all the oil until many pore volumes of solution have been injected. The other process involves a small slug (3 to 30 percent pore volume) of a high concentration solution which displaces 100 percent of the contacted oil as it moves through the reservoir. The higher displacement likely occurs because the concentration is initially miscible with the oil. The slug is gradually diluted by formation fluids and adsorption which destroys the miscibility. Further displacement may occur from reduction of interfacial tension as in the low concentration flood.[19] Laboratory results surveyed by Gogarty suggest the high concentration approach is superior. Although production starts later and continues for a shorter period of time, it is maintained at a higher rate and produces greater ultimate recovery.[20] The shorter production period would provide a significant advantage in terms of net present value even if ultimate recovery is approximately the same for both processes.

3.5.3 Alkaline Flooding[21]

Alkaline or caustic methods involve the introduction of an alkali such as sodium carbonate, sodium silicate or sodium hydroxide into the waterflood. There are at least four different mechanisms by which such solutions are thought to increase recovery:

1. emulsification and entrainment
2. emulsification and entrapment
3. wettability reversal (oil wet to water wet)
4. wettability reversal (water wet to oil wet)

When emulsions are formed in the processes, demulsification costs must also be considered.

Emulsification and Entrainment

The first mechanism operates when the sodium hydroxide reacts with the acids in the oil, thereby reducing interfacial tension which allows formation of emulsifying soaps. The oil-in-water emulsion becomes strung out in the flowing alkaline solution and is produced with it. Reisberg and Doscher suggested that the mechanism is not likely to be effective because for various reasons the alkali is quite likely to fall behind the displacement front, delaying production until several pore volumes of the solution have been injected. This would adversely affect the economics of the operation.

Emulsification and Entrapment

In this case the reduction in interfacial tension again leads to emulsification of oil droplets which are quickly trapped again by small pore throats. These droplets reduce the mobility of water through the reservoir causing a significant increase in volumetric sweep efficiency. Residual oil saturation is not reduced by this method since the trapped emulsion droplets do not get produced. Therefore, the indicated application is in reservoirs that suffer from poor sweep efficiency (high viscosity oils). An implication is that when entrapment is thought to be the primary mechanism, the process must compete with thermal and polymer methods which are also effective with viscous oils.

Wettability Reversal (Oil Wet to Water Wet)

In this case the alkali solution acts to reverse the preference of the rock from oil to water. This favourably affects the relative permeabilities to the fluids making it easier for oil to flow (i.e., improving the mobility ratio).

Wettability Reversal (Water Wet to Oil Wet)

In this case the reversal is accompanied by a significant reduction in interfacial tensions caused by the formation of soaps when the alkali reacts with the acids in the oil. The wettability reversal changes the condition of the oil from droplets surrounded and trapped by water to a thin film on the rock surface, which provides a flow path. The low interfacial tension causes a water-in-oil emulsion to develop. These emulsion droplets are interspersed with oil droplets in the pores. The emulsion droplets block flow causing a pressure build-up sufficient to overcome the weakened capillary forces and allowing the oil drops to escape. Thus the mechanism works by reducing residual oil saturation (possibly to as low as 5 percent pore volume).

All of the above mechanisms may be improved with the use of polymers for greater mobility control. Another approach is to inject alternate slugs of sodium silicate and calcium chloride. In the reservoir, these chemicals mix and precipitate calcium silicate which may plug the strata as they are flooded out.

3.5.4 Hydrocarbon Miscible

In these processes the injected hydrocarbon mixes fully with the reservoir oil, completely eliminating any interface that would occur with an immiscible displacing fluid such as water. The potential for 100 percent recovery is theoretically possible and has been demonstrated in the laboratory, but not in the field.

Three basic processes may be distinguished, high pressure (vaporizing) gas drive, enriched (condensing) gas drive, and miscible slug processes.[22] The miscible process involves injection of a slug of LPG or liquid propane followed by natural gas. The slug mixes with the reservoir oil and is driven to the wellhead by the natural gas. High pressures are required to maintain the process (1,200 psi). While these pressures will not damage most reservoirs, they are undesirable if lower pressure methods can be found.

The high pressure gas drive works by inducing vaporization of intermediate hydrocarbons (C_2-C_6) from the reservoir oil. The injected gas reduces the distance between molecules of the hydrocarbon, thereby increasing molecular attraction and 'extracting' some of the molecules from their liquid phase into a gaseous phase. The addition of the heavier molecules tends to alter the composition of the gas towards that of the liquid hydrocarbon from which it is 'stealing'. The process continues until the injected gas is completely miscible with the reservoir oil. It may be viewed as in situ production of a miscible slug. The pressure required is about three times that required for the injected miscible slug process which limits its use. It is also limited to reservoirs with large proportions of intermediates in the crude.

The enriched gas process involves injection of a natural gas to which ethane, propane and butane have been added. In contrast with the reservoir oil these components condense, increasing the oil volume and decreasing its viscosity. Eventually this results in complete miscibility of the oil and injected gas. It is also therefore similar to the first process described except that the miscible slug is produced in situ by condensation. It is applicable under a wide range of reservoir pressure conditions (1,500-3,000 psi).

3.5.5 Carbon Dioxide (Miscible and Immiscible)

The CO_2 miscible process operates similarly to high pressure gas drive by in situ production of miscible conditions. However, the CO_2 vaporizes heavier hydrocarbons from the oil, which makes it applicable to a wider range of reservoirs.[23] It also requires much lower pressure conditions than the high pressure drive process. Actual recovery is not limited to miscible processes but includes immiscible mechanisms as well. These mechanisms are thought to include viscosity reduction, swelling of oil, vaporization of the crude, creation of solution gas drive, and increase in rock permeability. Viscosity is reduced 10 to 100 fold which improves mobility ratios and therefore sweep efficiencies. Oil volume may be swelled by 10 to 40 percent by dissolved CO_2. The residual saturations left behind will also be, in part, carbon dioxide. After the flood front has passed, continued production with attendant pressure declines allows some CO_2 to come out of solution displacing oil toward the wellhead as in solution gas drive. The possibility exists, however, that asphalts in some crudes may be precipitated when contacted with CO_2, thus plugging formations.

It is usually necessary to take some steps to increase the sweep efficiency of the CO_2 process. This can be done by alternate or simultaneous water injection, vertical displacement, and selective injection. Simultaneous water injection reduces mobility and prevents fingering. It also reduces the tendency for the gas to bypass the oil when high permeability zones are encountered. Vertical, rather than horizontal displacement, increases sweep by reducing the tendency of the lighter gas to overflow the oil.

The process seems to be more effective at lower production rates according to laboratory work reported by Holm.[24] In spite of the fact that much of the CO_2 can be recycled, economic viability will depend on the availability of CO_2 in sufficient quantities at reasonable costs. Considerable effort in developing such sources is justified by the fact that the process is one of few that shows promise in carbonate reservoirs, which contain something over half of Canadian reserves (see Appendix A).

3.5.6 Thermal Methods

Recovery of heavy oils is aided by heat, which reduces oil viscosity to levels that allow flow through the reservoir. Subsidiary effects include thermal expansion, increased sweep efficiency due to the improved mobility ratio, and steam distillation effects.[25] The heat may be introduced to the reservoir externally via steam or hot water or it may be generated in situ by combustion of a portion of reservoir crude. The major problems of the former process have to do with heat losses between steam production and the reservoir. In situ problems include:

1. inability of the oil to deposit sufficient fuel to support combustion;
2. low air injectivity;
3. cross chanelling and leaking of the injected air from the formation;
4. excessive air requirements;
5. low air saturation;
6. plugging of porous rock leading to the flow of a limited supply of air; and
7. mechanical problems in producing wells.[26]

Examples of the various procedures will be discussed briefly below.

Cyclic Steam Injection

This is sometimes referred to as steam soak or huff and puff. Steam is injected into the reservoir (huff) through a producing well. The well may then be shut-in for a time to allow the steam to 'soak' the area around the wellbore. The reduced viscosity oil is then produced (puff) over several months to a year until another injection is required. The cycle is usually repeated several times until incremental production ceases to justify it, at which time the operator sometimes switches to steam drive methods. Cyclic injection is one of the few enhanced recovery processes that has been commercially successful. In fact, one major U.S. investigation did not even consider it under their definition of enhanced recovery.[27]

Steam Drive

In this case steam is introduced to the reservoir continuously through injection wells and displaces the oil toward the producing wells. It may, but need not, follow several cycles of steam injection. At the steam front some condensation occurs, thus hot water moves through the lower zone of the sand and steam moves through the upper zones. Lower viscosity results in both zones, but in the hot water zone there may also be some increase in relative permeability to oil, while in the steam zone vapourization of lighter fractions contributes some of the incremental oil.[28] Much of the heat is lost to the formation in the process and this heat may be 'scavenged' by a follow-up cold water flood which increases recovery even further. Steam drive is not in excessive use at present, but its use will increase significantly in the U.S. as current cyclic injection projects are run down and are converted.

Hot Water

Hot water injection is rarely used because it is less economical than by steam methods. However, there are some situations in which the use of steam might lead to formation damage, in which case hot water could be used.[29]

In Situ Forward Dry Combustion (Fire Flood)

In this process the heat is produced by burning some of the crude within the reservoir itself. This is accomplished by sustained injection of air which, if the contacted crude oxidizes rapidly, may ignite spontaneously, or if oxidization is slow, can be artificially ignited. Post ignition injection of air causes a burning front to move away from the injection well. At the burning front, water is being vapourized and oil is being vapourized and cracked leaving a residue of coke to maintain combustion. The produced steam and oil vapour moves ahead of the front with the steam condensing to hot water which mobilizes the oil forming an oil bank which is pushed toward the producing wells.

Forward Wet Combustion

Wet combustion involves injection of water behind a flame front in an attempt to recapture the heat between the injector and the front. Over half of the heat produced is left in this region. The residual heat vapourizes the injected water and the resulting steam front overtakes the combustion front, transferring heat in front of it. The advantage lies in extending the heat zone further into the reservoir and perhaps even reducing the fuel requirement.

Reverse Combustion

This method, although at the experimental stage, seems to be suited to very heavy crudes. It begins as a forward combustion project, but after the front has burned out a short distance into the reservoir, air injection is shifted to other wells. The oil near the front is cracked and the lighter fractions pass through the combustion area as gases, moving toward the initial injection well which is now a producer. These hydrocarbon gases condense as the temperature cools and are produced as liquids. The process is assisted by general conduction of heat throughout the reservoir which lowers viscosity and mobilizes some oil that can move to the production well without passing through the combustion front.

The procedure requires about twice the amount of air needed for forward combustion but this may be an acceptable expense when no other recovery methods seem possible, which is likely to be the case when reverse combustion is used. About 50 percent of the residual oil may be expected to be recovered. A problem may occur due to spontaneous combustion at the injection wells which complicates field tests with a second flood front. But the potential for this process in the far north has been noted. At low temperatures, around freezing, spontaneous ignition time requirements would be several years which is enough time for a test to be completed.

A variation of this process, reminiscent of cyclic steam injection, is to shut the air off after some period of time, terminating combustion and allowing the oil to move toward the producing well (former injector) without passing through the combustion front.

Footnotes

[1] There are numbers of different types and shapes of reservoirs which are classified according to the geologic features causing their occurrence (ie. structural folding, faulting, non-conformity, permeability variation, etc.). See Norman J. Clark, Elements of Petroleum Reservoirs, (Dallas, Society of Petroleum Engineers, 1960) Ch. 1.

[2] See Clark, Ch. 4.

[3] J.C. Calhoun, Jr., Fundamentals of Reservoir Engineering, (The U. of Oklahoma Press, Norman, 1960).

[4] This vivid analogy is suggested by Clarke, Ch. 4.

[5] This explanation relates to water wet reservoirs (ie., the rock prefers adhesion with water). Some reservoirs are oil wet. The connate water saturation in water wet reservoirs is usually quite a bit higher than in oil wet reservoirs (25 per cent or more versus 10 per cent or less). However, most reservoirs exhibit intermediate wettability, that is the rock has no strong preference for either oil or water.

[6] B.C. Craft and M.F. Hawkins, Applied Petroleum Reservoir Engineering, (Englewood Cliffs, N.J., Prentice Hall, 1959), Ch.1, Norman J. Clarks, op. cit., Ch. 5,7.

[7] Ben H. Caudle, Introduction to Reservoir Engineering, (Society of Petroleum Engineers of AIME, 1976), p. 31.

[8] This may not correspond to the proportion of reserves that lie underneath but because the actual extent of the reservoir cannot be determined it is felt to be the fairest method.

[9] D.N. Stright, Jr., D.W. Bannion and K. Aziz, "Influence of Production Rate on the Recovery of Oil from Horizontal Waterfloods." Journal of Petroleum Technology, May, 1975, pp. 555-563; R.T. Miller and W.C. Rogers, "Performance of Oil Wells in Water Drive Reservoirs." Paper SPE 4633, SPE-AIME 48th Annual Meeting, Las Vegas, Nevada, Sept. 30 - Oct. 3, 1973.

[10] This is the definition adopted by the Alberta Energy Resources Conservation Board. ERCB 77-18, Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, (Calgary, 1977).

[11] National Petroleum Council, Enhanced Oil Recovery, December 1976.

[12] The ERCB estimates that "about 70% of Alberta's conventional crude oil reserves will in due course be associated with water production." This includes water from natural aquifers but the bulk of it would be due to the waterflooding projects that were in operation in 1975. ERCB 76-18, Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, December 31, 1975.

[13] A complete list of factors is discussed by J.W. Amyz and D.M. Bars, Jr., "Estimating Secondary Reserves," AIME (1958), Vol. 213.

[14] It also varies with mobility ratios. For M=10 sweep efficiency at breakthrough is only 50 per cent, whereas if M=0.2 sweep efficiency at breakthrough is about 100 per cent. *Secondary and Tertiary Oil Recovery Process*, (Oklahoma City, Interstate Oil Compact Commission, 1974).

[15] Actually the relevant variable is flow potential which adjusts pressure for density, gravity segregation and height effects. Flow potential will equal pressure only if the fluid movement is on a horizontal plane. However, for our expositional purposes this refinement detracts more than it adds.

[16] This applies to a single incompressible fluid that does not react with the medium through which it is flowing. When the fluid is compressible, such as oil, the flow rate also depends on the level of the pressure in the reservoir.

[17] D.H. Stright, *The Use of Polymers for Enhanced Oil Recovery: A Review*. (Calgary, Petroleum Recovery Institute Applications Report AR-2, December 1976). Stright cites B.B. Sandiford, "Flow of Polymers Through Porous Media in Relation to Oil Displacement", paper delivered at the Improved Oil Recovery Symposium of the American Institute of Chemical Engineers, Kansas City, 1976.

[18] W.B. Gogarty, "Status of Surfactant or Micellar Methods", *Journal of Petroleum Technology*, January 1976, pp. 93-102.

[19] Todd M. Doscher, "Tertiary Recovery of Crude Oil" in *The Future Supply of Nature Made Petroleum and Gas*, R.F. Meyer, ed. (New York, Pergamon Press, 1977).

[20] Gogarty, "Status of Surtactant of Micellar Methods."

[21] This discussion is based primarily on C.E. Johnson, "Status of Caustic and Emulsion Methods", *Journal of Petroleum Technology*, January 1976, pp. 85-92.

[22] Interstate Oil Compact Commission, *Secondary and Tertiary Oil Recovery Processes*, p. 42.

[23] L.W. Holm and V.A. Jorendal, "Mechanisms of Oil Displacement by Carbon Dioxide", *Journal of Petroleum Technology*, December 1974, pp. 1427-1436.

[24] L.W. Holm, Status of CO_2 and Hydrocarbon Miscible Oil Recovery Methods, *Journal of Petroleum Techniology*, January, 1976, pp. 76-84.

[25] S.M. Faroul Ali, *Secondary and Tertiary Oil Recovery Process*, Ch. 6.

[26] N. Gangoli and George Thados, "Enhanced Oil Recovery Techniques - State of the Art Review", Journal of Canadian Petroleum Technology, October to December 1977, pp. 13-20.

[27] Gulf Universities Research Consortium, Report 140, An Investigation of Primary Factors Affecting Federal Participation in R and D Pertaining to the Accelerated Production of Crude Oil, (Texas, 1974) p.34.

[28] National Petroleum Council, Enhanced Oil Recovery.

[29] S.M. Farouq Ali, op. cit., p. 146.

CHAPTER 4

ECONOMIC MODELS OF THE RECOVERY PROCESSES

4.1 An Overview of the Models

The models of production and economics are intended to characterize standard development and operation of enhanced recovery projects. The models are applied to all reservoirs that appear technically viable using current technology. 'Technically viable' means without regard to costs of development, and the procedure used to establish technical viability is a screening procedure developed by the Petroleum Recovery Institute (see 4.2).

The inputs to the models are reservoir characteristics (described in Appendix A), cost estimates (described in Appendix B), production assumptions (described below), and tax and royalty regulations (described in Appendix C). The models generate for each reservoir:

- the quantity of incremental oil production attributable to the enhanced recovery project
- the time profile of production of this incremental oil (and associated cash flows)
- three indicators of economic viability, calculated with and without tax and royalty considerations
  1) the 'supply price' for the project (the price per barrel required to recover all development costs)
  2) the net present value of the projected production
  3) the project's internal rate of return
- federal and provincial revenues generated by the project

The generation of the primary output described above involves the calculation of a number of variables of subsidiary interest which are also recorded for each reservoir. These include original and remaining oil in place, new wells required, surface acreage utilized, capital, operating, and materials costs, and quantities of injection materials required.

Selected variables of particular interest have been aggregated to determine the impact and potential of enhanced recovery prospects in Alberta. Extension to other provinces is accomplished by an extrapolation process.

The remainder of this chapter describes the procedures developed to analyse individual reservoirs. The discussion has five main sections:

- the technical screening procedure
- estimating incremental recovery
- general design of the production models
- design of production models for specific processes
- economic evaluation

4.2 Technical Screening Procedure

The Energy Resources Conservation Board in Calgary publishes yearly updates of Alberta's reservoirs of crude oil. For each reservoir the Board provides estimates of original oil in place, potential recovery from primary and secondary methods, and remaining oil in place.[1] These estimates provide a starting point for an estimation of enhanced recovery potential. The first step is to check each reservoir to determine if it is likely to be susceptible to any of the various enhanced recovery processes and to catalogue them according to which process is most likely to be successful. This, of course, is a complex technical procedure which must take account of the reservoir characteristics and somehow determine whether these characteristics indicate a preferred recovery process. Over the past several years, the Petroleum Recovery Institute has been reviewing the state of knowledge that has emerged from theoretical studies, laboratory experiments and field pilot tests. This knowledge has been distilled to produce a screening procedure which enables us to catalogue the existing reservoirs, not only as to whether or not they are suitable for enhanced recovery operations, but also according to the technique for which each reservoir might be considered. The screening procedure is, of course, critical to all other results.[2] It is discussed in greater detail in Appendix A.

4.3 Estimating Incremental Recovery in Qualifying Reservoirs

The estimate of potential incremental recovery attributable to a given process is given by the difference between oil in place before the process is tried and oil in place after it is tried. Defined in terms of volumetric estimates of oil in place and residual oil saturation levels (the percentage of pore space taken up by oil), we have the following expression for incremental recovery.

$$1) \quad IR = \left[\frac{OOIP \times B_{oi}}{1 - S_w}\right] (S_{orw} - S_{ort}) \frac{E}{B_o}$$

where

IR is incremental recovery

OOIP is original oil in place

B_{oi} is initial oil formation volume factor (the ratio of the volume in barrels that a stock tank barrel occupies in the reservoir to a stock tank barrel at standard temperature and pressure--14.4°C and 1 atmosphere)

B_o is current oil formation volume factor

S_w is water saturation (proportion of pore space occupied by water)

S_{orw} is residual oil saturation after waterflood

S_{ort} is residual oil saturation after tertiary application

E is volumetric sweep efficiency (the proportion of the reservoir contacted by the displacing medium)

The square bracketed term on the right hand side represents the hydrocarbon pore volume, the second bracketed term is the change in residual oil saturation, and the third term makes allowance for the sweep efficiency and the tendency for shrinkage to occur when the oil is produced.

The expression (but not the estimating procedure) is somewhat simplified as formulated by Lewin and Associates and the Petroleum Recovery Institute.[3]

$$2)\quad IR = \frac{S_{orw} - S_{ort}}{S_{orw}} \cdot ROIP$$

where

ROIP is remaining oil in place after ultimate primary and secondary production.

The other variables are as defined above and the first term on the right hand side is the recovery factor. The problem then is to obtain values for residual oil saturation after waterflood and estimates of values after a tertiary process has been tried for each of the reservoirs in our data base. The value for residual oil saturation after tertiary production for each process depends on the residual saturation after secondary production (waterflood) and on the sweep efficiency and displacement efficiency associated with each process. In each case the sweep efficiency is an assumed value and the displacement efficiency is reflected in the assumed residual saturation after the process has been applied. These values are based on theoretical and empirical considerations tempered by practical experience. They were developed by Lewin and Associates in a 1976 study for the United States Federal Energy Administration.[4] They are also being used by the Petroleum Recovery Institute and so have been accepted here. As an example, for a steam drive process which has two zones, a steam zone and a hot water zone, the formula might be as follows:

$$3)\quad \underbrace{S_{ort}}_{\text{Residual oil saturation after EOR}} = \underbrace{0.40}_{\text{Sweep efficiency in steam zone}}\ (\underbrace{0.08}_{\text{Residual oil saturation in steam zone}}) + \underbrace{0.35}_{\text{Sweep efficiency in hot water zone}}\ (\underbrace{0.25}_{\text{Residual oil saturation in hot water zone}}) + \underbrace{0.25}_{\text{Unswept proportion}}\ (\underbrace{S_{orw}}_{\text{Residual saturation before steam flood}})$$

In the case of microemulsion flooding, theoretical considerations lead to the assumption that residual saturation in the swept zone will be 0.08 and sweep efficiency will be 60 percent of the reservoir volume. The unswept 40 percent of the reservoir will, of course, end up with the same oil saturation as it started with. So the saturation after flooding can be expressed as

4) $S_{ort} = 0.60\ (0.08) + 0.40\ (S_{orw})$

For alkaline flooding the assumed values yield the relationship

5) $S_{ort} = 0.50\ (0.15) + 0.50\ (S_{orw})$

For steam drive, a distinction is made between highly viscous (greater than 1000 cp) and low viscosity (less than 1000 cp) reservoirs. In these cases the reservoir is swept not only by steam, but also by a hot water phase (as the steam condenses). For viscous reservoirs, residual saturation is assumed to be 0.30 in the hot water zone and 0.08 in the steam zone with sweep efficiencies in both zones of 35 percent.

6) $S_{ort} = 0.35\ (0.08) + 0.35\ (0.30) + 0.30\ (S_{orw})$

For low viscosity reservoirs, residual saturation is assumed to be 0.08 in the steam swept zone with 40 percent sweep efficiency and 0.25 in the hot water zone with 35 percent sweep efficiency. Thus,

7) $S_{ort} = 0.40\ (0.08) + 0.35\ (0.25) + 0.25\ (S_{orw})$

The in situ combustion case also considers two zones, the burn zone and the condensation zone, and reservoirs are distinguished as to whether viscosity is greater or less than 40 cp. The more viscous reservoirs are assumed to have 30 percent sweep efficiency in both zones with residual saturation of 0 in the burn zone and 0.35 in the condensation zone. Therefore,

$$8)\quad S_{ort} = 0.30\ (0.00) + 0.30\ (0.35) + 0.40\ (S_{orw})$$

Low viscosity reservoirs perform slightly better.

$$9)\quad S_{ort} = 0.35\ (0.00) + 0.35\ (0.30) + 0.30\ (S_{orw})$$

It should also be noted that in these cases incremental recovery must be reduced by the amount of oil burned in the combustion zone. Thus, incremental recovery would be estimated as

$$10)\quad IR = \left[\frac{S_{orw} - S_{ort}}{S_{orw}} \cdot ROIP\right] - \text{oil burned in combustion zone}$$

In the case of CO_2 miscible flooding, sweep efficiency depends on the level of primary and secondary recovery prior to institution of the CO_2 process. The assumed relationship is as follows:

Primary/Secondary Recovery %	CO_2 Sweep Efficiency % After Primary	CO_2 Sweep Efficiency % After Secondary
0 - 30	30	20
30 - 50	40	30
>50	40	40

The residual saturation formulas discussed in the previous paragraphs are summarized in Table 4.1.

The values for residual saturation after waterflood depend on how uniformly the residual oil is distributed in the reservoir. This distribution is, of course, unknown but some allowance can be made for uniform versus non-uniform distributions in the following way:

(a) When total recovery is greater than 55 percent with sweep efficiency exceeding 65 percent, it may be assumed that the oil is uniformly distributed within the reservoir. In this case, the estimate of S_{orw} is simply:

$$\text{11)} \quad \frac{\text{OOIP - production}}{\text{OOIP}} \cdot S_o$$

where

OOIP is original oil in place

S_o is initial oil saturation

This is merely the percentage produced times the percentage that was there to begin with. As a practical matter, sweep efficiency (which may be estimated for an individual reservoir) is an unknown variable in aggregate estimation and so our estimates adopt this approach in any cases where recovery from primary and secondary operations exceeds 55 percent.

(b) When recoveries are less than 55 percent, it is assumed that residual oil is non-uniformly distributed throughout the reservoir. In this case, we use a value for S_{orw} for the waterflooded

TABLE 4.1

CALCULATION OF RESIDUAL OIL SATURATION AFTER VARIOUS PROCESSES

Process	Residual Saturation after Tertiary
Microemulsion	$S_{ort} = 0.60\ (0.08) + 0.40\ (S_{orw})$
Alkaline Flooding	$S_{ort} = 0.50\ (0.15) + 0.50\ (S_{orw})$
CO_2 Miscible[a]	$S_{ort} = (0.20 - 0.40)(0.08) + (0.8 - 0.60)\ (S_{orw})$
Steam Drive[b]	
Viscosity > 1,000 cp.	$S_{ort} = 0.35\ (0.08) + 0.35\ (0.30) + 0.30\ (S_{orw})$
Viscosity < 1,000 cp.	$S_{ort} = 0.40\ (0.08) + 0.35\ (0.25) + 0.25\ (S_{orw})$
In Situ Combustion[c]	
Viscosity > 40 cp.	$S_{ort} = 0.30\ (0.00) + 0.30\ (0.35) + 0.40\ (S_{orw})$
Viscosity < 40 cp.	$S_{ort} = 0.35\ (0.00) + 0.35\ (0.30) + 0.30\ (S_{orw})$

[a] See text for the explanation of this assumed range for sweep efficiencies.
[b] In this case there are two zones, the steam zone and the hot water zone.
[c] In this case there are two zones, the burn zone and the condensation zone.

zone only. Again, for any individual reservoir, this value may be calculated if sufficient information is available. For aggregate estimation, this approach is not feasible and an alternate method was required. The Energy Resources Conservation Board was able to provide residual oil saturation values after waterflood for Alberta pools. These are presented in Table 4.2 which shows approximate average values for nine major geological formations. These averages were obtained by a random survey of values used by the Board in some of the prominent pools and some of the recently reviewed pools in each of the formations. Values used in individual pools within a formation may vary by up to ±5 percent from the average listed values. The values shown apply only to the portions of the reservoir which have undergone water displacement.

TABLE 4.2

RESIDUAL OIL SATURATIONS AFTER WATERFLOOD
ALBERTA OIL POOLS

Formation	Residual Oil Saturation After Waterflood (percent of pore volume)
Keg River	30
Beaverhill Lake	37
D-3 (Leduc)	25
D-2 (Nisku)	30
Mississippian	35
Triassic - Jurassic	32
Manville	30
Viking	30
Cardium	40

SOURCE: ERCB private communication.

NOTE: The values of S_{orw} listed above apply to 65.4 percent of the reservoirs that emerged from the screening procedure. In the other 34.6 percent of the reservoirs S_{orw} is either calculated with the use of equation 11 or is assumed to be 30 percent.

Incremental recovery for polymer flooding and cyclic steam injection processes is not estimated using the above procedures. This is primarily because these processes may not affect actual displacement efficiency but rather affect the proportion of the reservoir contacted by the displacing fluid. Polymer floods are implemented in place of a straight waterflood and the National Petroleum Council's review of field experience suggested that incremental recovery will be of the order of 15 percent above what it would have been with waterflood only. Therefore, these estimates are applied directly to the oil in place that the screening process suggested would be amenable to polymer methods. Steam stimulation methods are assumed to increase recovery by 25 percent.

4.3.1 Evaluation of the Incremental Recovery Estimation Procedure

The method adopted to estimate incremental recovery in each reservoir is, of course, critical to the overall results. Some indication of the sensitivity of the results to this calculation of the recovery factor (ΔR) is in order because there are some theoretical ambiguities in the procedure.

The main problem occurs because oil is not uniformly distributed throughout reservoirs. In over half the cases studied we used an estimate of S_{orw} provided by the Energy Resources Conservation Board. The estimates were based on relatively detailed knowledge of the characteristics and production history in the formations but they apply only to the portion of the reservoir that is actually contacted by water. A very rough calculation of this proportion for the Alberta reservoirs under consideration yields an estimate of 70 percent.[5]

But the procedure used here to determine S_{ort} involves an implicit assumption that waterflood conformance is 100 percent, that is, 100 percent of the reservoir is actually contacted by water. This can be seen from the formula for S_{ort} for steam drive repeated below.

Determination of S_{ort}

$$\underbrace{S_{ort}}_{\text{Residual oil saturation after EOR}} = \underbrace{0.40}_{\text{Sweep efficiency in steam zone}}\ \underbrace{(0.08)}_{\text{Residual oil saturation in steam zone}} + \underbrace{0.35}_{\text{Sweep efficiency in hot water zone}}\ \underbrace{(0.25)}_{\text{Residual oil saturation in hot water zone}} + \underbrace{0.25}_{\text{Unswept proportion}}\ \underbrace{(S_{orw})}_{\text{Residual saturation before steam flood}}$$

In this formula the last term indicates the 25 percent of the reservoir that is not contacted by the tertiary process has a residual saturation after waterflood of S_{orw}, say 30 percent. This 30 percent, however, actually applies only to the part of the reservoir contacted by water. Some of the reservoir is not so contacted and so the remaining average oil saturation is somewhat higher than 30 percent. Thus, S_{ort} is underestimated. But that means ΔR would be overestimated since it is calculated as:

$$\Delta R = \frac{S_{orw} - S_{ort}}{S_{orw}}$$

In other words, if the tertiary flood follows the same path as the waterflood (the swept zone is the same) the recovery could be very much less than estimated here.

This is mitigated to some extent by the fact that the use of the Board's S_{orw} underestimates the oil remaining since the saturation is higher in areas of the reservoir that were not contacted by waterflood. If the tertiary procedure increases conformance as well as displacement efficiency, there is a possibility that recovery would be higher than indicated by the recovery factor. In fact, this result is quite possible for a number of reasons. First, tertiary processes involve closer spacing which allows some possibility of crossflooding to ensure as far as possible that the tertiary flood does not merely follow the same channels as the waterflood. Also, operations are enhanced by the better reservoir definition possible with closer well spacing. Finally, it provides better flexibility of operation. This refers to the impact of any problems of specific wells. In wide spacing, problems with a particular well have a proportionately greater impact than in closer spacing.

Since it is not clear on theoretical grounds alone whether the procedure overestimates or underestimates ultimate incremental recovery, we carried out a few tests to illuminate the relationship between S_{orw}, S_{ort} and incremental recovery (ΔR).

Table 4.3 shows the results of a 10 percent change in S_{orw} on calculated S_{ort} and the calculated recovery factor. The attendant change in S_{ort} is slightly less than 10 percent but the change in the recovery factor is considerably less, about 3 percent in most cases. The sensitivity of recovery factor to changes in S_{orw} is quite small.

TABLE 4.3

SENSITIVITY OF S_{ort} AND RECOVERY FACTOR TO CHANGES IN S_{orw}

	S_{orw}	ΔS_{orw} (%)	ΔS_{ort} (%)	Recovery Factor (ΔR) (%)
Miscible gas	0.4	10	9	3
Microemulsion	0.4	10	7	3
Alkaline	0.4	10	7	6
Steam drive	0.7	10	6	3
In situ	0.7	10	7	3

The average recovery factors for reservoirs that would actually be developed in our base case are shown in Table 4.4. These factors do not appear unreasonable, especially considering they are averages for the qualifying reservoirs only. Reservoirs with low recovery factors likely turned out to be uneconomical and were thus omitted from the average.

TABLE 4.4

AVERAGE RECOVERY FACTORS FOR DEVELOPED RESERVOIRS IN THE BASE CASE SIMULATION

	Average Recovery Factor (% ROIP)
Alkaline	23.4
Polymer	6.0
Microemulsion	40.0
Hydrocarbon miscible	
Sandstone	15.3
Carbonate	17.7
Weighted average	15.9
Carbon dioxide miscible	
Sandstone	17.5
Carbonate	21.7
Weighted average	21.3
Steam drive	55.4
Steam cycle	23.0
In situ combustion	48.4

To check the aggregate effect on recovery of a much reduced S_{orw} we did a test run on the hydrocarbon miscible process. We chose this process because it involves a large number of reservoirs containing a large amount of remaining oil in place (8.5 billion barrels).

In each reservoir the assumed residual oil saturation after waterflood was reduced by 25 percent. The results are shown in Table 4.5.

TABLE 4.5

EFFECT OF REDUCING S_{orw} BY 25 PERCENT
ON HYDROCARBON MISCIBLE RECOVERY

ROIP	8.50 billion bbls	
Base case recovery	1.35 billion bbls	(15.9%)
Recovery if S_{orw} is reduced by 25%	1.19 billion bbls	(14.0%)
Difference	0.16 billion bbls	(1.9%)
	(12% of base case recovery)	

A 25 percent reduction in S_{orw} reduces the base case recovery by 12 percent, from 15.9 percent to 14 percent of remaining oil in place. Thus, in aggregate terms as well, the model does not appear to be critically sensitive to reasonable changes in the assumption of oil saturation before the tertiary process is applied.

In conclusion, it should be noted that whatever the procedures used to estimate incremental recovery, the estimate is reduced by 8 percent in an attempt to allow for the fact that gross swept volume is reduced by irregular pool shapes which result in some parts of the reservoir being outside the pattern of development. This percentage allowance emerged from discussions with a number of industry representatives.

4.3.2 Predicting Waterflood Performance

It might be thought that some allowance would have to be made for reservoirs destined for, but not yet under, waterflood. It is almost automatic for reservoirs to move from primary production to waterflood because the economics is usually very favourable. In such cases, we should predict waterflood performance before attempting to apply our tertiary estimating procedure. This leads us to a staging problem in oil production, that is, ultimate effectiveness of a waterflood project depends to some extent on when the project is initiated. If primary production is run to the limit before initiating waterflood, then ultimate recovery may be significantly less than if the flood had been instituted early. In fact, some waterfloods are best started before any primary production has occurred (and this may be true for some tertiary recovery as well). The nature of the problem is illustrated qualitatively in Figure 4.1 which shows that instituting secondary recovery before pressure has declined very far may result in increased ultimate recovery, which means smaller residual oil saturations. There are really two parts to the problem under consideration:

(a) the need to predict performance in reservoirs not yet under waterflood; and

(b) the need to allow for the stage at which waterflood was instituted when predicting residual saturations.

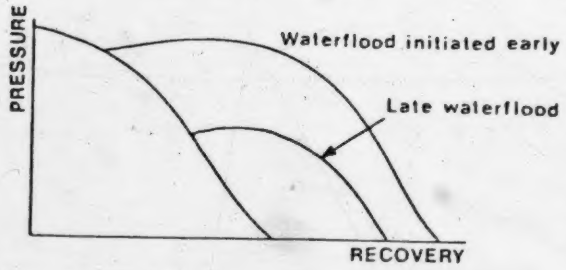


Figure 4.1 - Early waterflood may facilitate pressure maintenance at higher levels allowing larger ultimate recovery.

Although these questions need to be addressed, it appears that they are of little practical significance in Alberta. Reservoirs that may be intended for but are not yet under waterflood apparently represent an insignificant proportion of existing reserves. The amount of effort needed to prepare reliable predictions cannot be justified by the amount of oil involved. The reason for this situation is the strong incentives that exist for initiating waterfloods. Under prorationing, the allowable production per well depends on recoverable reserves so if water flooding can increase this amount the operators do not hesitate to bring it in. This, plus low costs, generally not more than fifty cents per barrel, result in waterflood usually being initiated within three years of going on primary production. Furthermore, the industry in Alberta has learned from United States' experience and so most waterfloods in the province were instituted at an early enough stage to ensure that ultimate recovery has not been adversely affected. This means the estimate of residual saturations provided by the ERCB should be consistent.[6]

4.4 General Design of the Production Models

Once an estimate of incremental recovery is developed, it is necessary to determine how production will take place. This requires assumptions regarding the pattern and area covered by a productive unit, the life of the productive unit, the productive life of the reservoir itself, and the number of stages over which the field will be developed. This provides a basis upon which the equipment requirements and costs can be estimated.

The specific assumptions differ according to the process under consideration and will be described more fully below. Some of the assumptions are based on the engineering literature that has grown up around the subject. This includes theoretical papers, reports of laboratory experiments and reports of field pilots. Other assumptions regarding the operation of the specific models used here have been made by the author.

Each model assumes a particular well pattern (usually a five-spot) and pattern size. Given the number of acres of a particular reservoir, these assumptions determine the number of patterns required and therefore the number of producing and injection wells and related capital equipment.

The productive years for each well (well life) is assumed to be the same for all wells in a particular process (e.g. seven years for steam drive, ten years for polymer flood). We assume that reservoirs would be developed in stages which begin one year apart. Each stage would involve a minimum of five patterns but there would be a maximum of ten stages of development for any reservoir. The life of the reservoir (field life) therefore depends on the assumed well life, the pattern size, and the size of the reservoir. For example, the steam drive process assumed five acre spacing with production occurring over seven years for each well. Therefore, a 25 acre reservoir would be developed in one stage (since we assume a minimum of five patterns per stage) and the field life would equal the well life (seven years). A 50 acre reservoir would, however, be developed in two stages beginning one year apart and therefore the field life would be eight years. A 250 acre reservoir would involve ten stages of five patterns each and the field life would be sixteen years. But any larger reservoirs would also be developed in ten stages over sixteen years. This would, however, mean that each stage would involve more than five patterns.

The time profile of injection is also unique to each process. For example, all steam drive patterns are assumed to involve steam injection of 5 percent pore volume in the first year and 2 percent pore volume in each of the remaining six years (see Appendix D). For each reservoir this assumption allows us to calculate the amount of injected material required, the number of injection units required (e.g. steam generators) and therefore the costs of required injection equipment.

Two assumptions are made which reflect the assumed sequential development of oil reservoirs and affect the assumed costs of development activity. First, in all cases we assume that waterflooding will occur prior to initiation of an enhanced recovery project. This secondary recovery activity is assumed to be carried out on eighty acre spacing. This means that fewer wells will have to be drilled by the time the tertiary recovery scheme is implemented. Second, we assume that capital equipment has some salvage value and in fact can be reused in some situations. For example, steam generators put in place in the first stage are only needed for the seven years that stage is assumed to operate. This means that if a field is large enough to involve eight stages the generator can be reused. If the field only involves six stages, however, reuse is not allowed in the model since the generators are still required in stage one when stage six begins. No generators are allowed to be transferred to different reservoirs. Thus, this is a fairly limited allowance within the models for 'recycling' capital equipment.

4.4.1 Feasibility of Implied Production and Injection Rates

The assumptions made about the amount of oil that can be produced from our assumed number of production wells over a specified time period implies a particular rate of production for each reservoir. Similarly injection rates are implied by our assumptions as to the number of injection wells and the amount of material to be injected over our assumed time period.

On the other hand, the rates of flow in an actual reservoir are governed by specific reservoir parameters such as the pressure differential, the distance between injector and producer, reservoir permeability, and the viscosity of the oil itself. The maximum theoretical flow rate for a five spot pattern is given by the following flow equation:[7]

$$Q = \frac{.003075\ khS\ \Delta P}{U\ [\log_{10} (\frac{d}{r_w}) - .619]}$$

where

d is the distance between injection and producing wells (ft)

r_w is the radius of the well bore (ft)

U is viscosity of the oil (centipoise)

ΔP is reservoir pressure minus bottom hole flowing pressure (BHFP assumed to be 200 psi for purpose of this check)

k is the permeability of the reservoir (millidarcies)

h is the pay thickness (ft)

S is the shrinkage factor (stock tank barrels ÷ reservoir barrels)

If the maximum assumed injection or production rate exceeds this theoretical flow rate (Q), it means our assumption regarding pattern size or the time profile of production may be unrealistic for this reservoir. By drilling more wells or extending the production profile over a longer time period, the maximum assumed production or injection rates per well can be reduced to the rates implied by the actual reservoir parameters. When this situation occurs in any of the models, we increase the number of wells drilled by 20 percent. If implied injection rates are too high, injection wells are supplemented. If implied production rates are too high, we increase production wells. If both are too high, both types of wells are increased. The procedure should be viewed as an order of magnitude check which prevents us from assuming a pattern size that requires a production or injection rate greater than the reservoirs could possibly handle. It is a compromise solution which would be too severe in cases where the theoretical maximum flow rate is exceeded by some small amount (possibly due to data inadequacies) and inadequate when the implied flow rate is, say, twice as high as it should be. But, on average, it is felt that the solution adjusts the total costs of developing reservoirs by a reasonable amount.

4.5 Design of Production Models For Specific Processes

The detailed production assumptions differ for each process and are presented in Appendix D. A summary of the basic assumptions used is provided in Tables 4.6 and 4.7.

4.6 Economic Evaluation

The economic evaluation utilizes discounted total revenues and costs to ascertain three criteria of economic viability, net present value, supply price, and internal rate of return. Treating time as a continuous variable

$$\text{12)}\quad NPV = \int_0^N [TR(t) - TC(t)]\, e^{-rt}\, dt$$

$$= \int_0^N [P(t)q(t) - CC(t) - OC(t)]\, e^{-rt}\, dt$$

where

NPV	is net present value
TR(t)	is total revenue
TC(t)	is total cost
P(t)	is price of oil
CC(t)	is capital costs
OC(t)	is operating costs
N	is life of the project
t	is time
r	is discount rate

TABLE 4.6

BASIC PATTERN ASSUMPTIONS

Process	Pattern	Size (acres)	Life (years)	Injection Materials
Steam drive	5-spot	5	7	Steam
Steam stimulation	--	5	variable	Steam
In situ combustion	9-spot	20	7	Air, water
Polymer augmented waterflood	5-spot	80	10	Polymer (250 ppm), water
Alkaline flood	5-spot	40	10	Sodium hydroxide (1,500 ppm) Polymer (250 ppm), water
Microemulsion flood	5-spot	20	8	Surfactant slug 6.5% surfactant by weight 1% alcohol by weight 10% oil by volume Polymer (600 ppm), water
Carbon dioxide miscible (sandstones)	5-spot	80	12	Purchased CO_2 Recycled CO_2, water
Carbon dioxide miscible (carbonates)	5-spot	80	12	Purchased CO_2 Recycled CO_2, water
Hydrocarbon miscible (sandstones & carbonates)	5-spot	80	12	LPG slug, methane, water

TABLE 4.7

INJECTION AND PRODUCTION SCHEDULE

Process	Injection (pore volumes/yr) Production (% of total)		Year 1	2	3	4	5	6	7	8	9	10	11	12
Steam drive	Injection schedule	Steam	.05	.2	.2	.2	.2	.2	.2					
	Production schedule		0	.1	.2	.22	.22	.16	.1					
Steam stimulation	Injection schedule		4 bbls steam per bbl oil produced											
	Production schedule		.14	.14	.14	.14	.14	.14	.14					
In situ combustion	Injection schedule	Air	2.5 - 3 MMscf/yr											
		Water	.5 bbl/Mscf of air injected											
	Production schedule		.1	.15	.21	.19	.16	.12	.07					
Polymer augmented waterflood	Injection schedule	Polymer	.05	.05	.05	.05	0	0	0	0	0	0		
		Water	0	0	0	0	.05	.05	.05	.05	.05	.05		
	Production schedule		0	.05	.1	.2	.2	.15	.1	.1	.05	.05		
Alkaline flood	Injection schedule	Sodium hydroxide	.08	.08	.08	0	0	0	0	0	0	0		
		Polymer	0	0	0	.05	.05	.05	.05	0	0	0		
		Water	0	0	0	0	0	0	0	.05	.05	.05		
	Production schedule		0	.01	.07	.16	.21	.21	.16	.11	.05	.02		
Microemulsion flood	Injection schedule	Surfactant	.085	0	0	0	0	0	0	0				
		Polymer	0	.75	.75	.75	0	0	0	0				
		Water	0	0	0	0	.75	.75	.75	.75				
	Production schedule		0	0	.1	.24	.29	.2	.1	.07				
Carbon dioxide miscible (sandstones)	Injection schedule	Purchased CO_2	.02	.02	.02	.018	.016	.014	.012	.01	.008	.008	.007	.006
		Recycled CO_2				.002	.004	.006	.008	.01	.012	.012	.013	.014
		Water	.02	.02	.02	.02	.02	.02	.02	.02	.02	.02	.02	.02
	Production schedule		0	0	.04	.07	.11	.15	.18	.14	.12	.1	.06	.03
Carbon dioxide miscible (carbonates)	Injection schedule	Purchased CO_2	.025	.025	.025	.023	.021	.019	.017	.015	.014	.013	.012	.011
		Recycled CO_2				.002	.004	.006	.008	.010	.011	.012	.013	.014
		Water	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025
	Production schedule		0	0	.04	.07	.11	.15	.18	.14	.12	.1	.06	.03
Hydrocarbon miscible (sandstones & carbonates)	Injection schedule	LPG	0	.025	.025	.025	.025	0	0	0	0	0	0	0
		Methane						.07	.07	.07	.07	0	0	0
		Water	.025	.025	.025	.025	.025	0	0	0	0	.025	.025	.025
	Production schedule		0	0	.04	.07	.11	.15	.18	.14	.12	.1	.06	.03

As a practical matter, we utilize the discrete version of 12), use mid-year discounting, and calculate net present value as follows:

13) $$NPV = \sum_{t=1}^{N} \frac{TR_t - TC_t}{(1 + r)^{t-.5}} = \sum_{t=0}^{N} \frac{p_t q_t - CC_t - OC_t}{(1 + r)^{t-.5}}$$

where

p_t is domestic wellhead price of oil in year t

q_t is production from the project in year t

TR_t is total revenue from the project in year t, $(p_t q_t)$

TC_t is total costs of the project in year t, $(CC_t + OC_t)$

CC_t is capital costs in year t

OC_t is operating costs in year t

r is discount rate chosen

The supply price is the revenue per barrel of oil produced that would be required to recover all development costs including a return on net investment. The technical calculation of the supply price makes use of the following formula.[8]

14) $$S_p = \frac{\displaystyle\sum_{t=1}^{N} \frac{OC_t + CC_t}{(1 + r)^{t-.5}}}{\displaystyle\sum_{t=1}^{N} \frac{q_t}{(1 + r)^{t-.5}}}$$

where S_p is supply price, and the other variables are as defined above.

S_p, the supply price for enhanced recovery production, allocates the same cost to every barrel produced over the life of the project. It is therefore an average incremental cost per present barrel equivalent. Considering the enhanced recovery project as marginal to total petroleum recovery, the supply price is really an average long run marginal cost.

The internal rate of return is that discount rate which equates discounted total revenues with discounted total costs (yields a zero net present value). That is, the solution to the following:

$$15)\quad 0 = \sum_{t=1}^{N} \frac{TR_t - TC_t}{(1 + r)^{t-.5}}$$

where the discount rate, r, required to solve the equation is referred to as the internal rate of return.

4.6.1 A Note on Methodology

The criteria embodied in equations 12 to 15 are utilized on the basis that the enhanced recovery projects are completely incremental to conventional primary and secondary recovery. This is the most appropriate analytical approach to existing reservoirs where primary and secondary recovery operations are currently underway. It allows us to neglect certain sunk costs, such as land acquisition costs, road development, and costs of equipment already in place. The evaluation of new discoveries would more appropriately adopt the analytical viewpoint that each phase of reservoir development be assigned its share of revenues from expected production and its share of all costs including those mentioned above. Nonetheless, having successfully implemented primary and secondary recovery operations, the decision to proceed with a tertiary scheme would be based on the 'incremental' approach used here.

There are, however, a number of problems associated with the aggregate analysis of large numbers of projects that are each specified by a form such as 12) and 13). In particular, the production rate, q_t, and project life, N, are related to the size and timing of capital expenditures. For example, the pattern and pattern size chosen determine the number of wells required, a major component of capital costs. If the technology were completely understood, it would be possible to maximize NPV by a suitable choice of pattern and pattern size. This would mean that N and the structure of q_t would be unique to each project. Unfortunately, the technology involved in enhanced recovery is far from being completely understood. We have therefore made standardized assumptions regarding the duration of projects within particular processes and the production and investment rates involved. These assumptions, described in the previous section, are based on informed judgment within the industry but they cannot possibly approximate the optimal development strategy that could be utilized in developing each of the reservoirs under consideration. This optimal strategy is a function of knowledge of individual reservoir characteristics. It also depends on the 'state of the art' for each process which one might expect to improve over time. However, no attempt has been made to incorporate technological advance in our estimation procedure. Aside from the difficulties of forecasting technological advance it is not clear whether such advance will allow us to recover significantly more oil or will merely allow us to better understand why we can't.

In any case, the technical models of production described in the preceding section serve essentially to identify the assumed extent and timing of the incremental production and the extent and timing of the real investment required to realize this production. These revenue and cost profiles are then incorporated in the formulae for the various economic criteria developed.

The oil price used here is an assumed domestic wellhead price which prevails over the life of the project. General inflation in both costs and prices is not considered (see section 4.6.4). However, a differential in the rate of increase of oil prices and development costs is allowed for in the sensitivity analysis by using prices (in 1978 dollars) of $15, $20 and $25 dollars per barrel with unchanged real costs of production. The price of oil may be reasonably expected to rise at a faster rate than development costs (even in the absence of a cartel) since it is a depleting resource. Each of the three price assumptions are assumed to prevail over the entire period of analysis.

4.6.2 Risk

Tertiary recovery projects are inherently risky due to reservoir uncertainties and inadequate technical understanding of the various recovery processes. This is mitigated to some extent by the stringent screening procedure but considerable risk remains. However, a study by Lewin and Associates suggested that "the economic effects of risk and failure may be lower than generally perceived."[9] Assuming each reservoir will try two pilots on 10 percent of the acreage, each being twice as costly per acre as full reservoir development and failing in one out of ten reservoirs (of randomly selected size) they calculate a risk premium of 2.2 percent of investment costs from the following formula.

16) $$\frac{\text{Pilot cost per acre x pilot acreage x probability of failure}}{\text{Reservoir cost per acre x reservoir acreage x (1-probability of failure)}}$$

$$= \frac{2 \times 10 \times 0.1}{1 \times 100 \times (1-0.1)} = 2.2\%$$

Our models incorporated the procedure suggested by the Lewin study to allow for overhead and administration costs, namely 4 percent of capital investment costs and 20 percent of operating costs. This incorporates a generous allowance for the risk that projects qualifying at the screening stage are unsuccessful at the pilot project stage of development. In addition, sensitivity analysis allows us to consider the effects of varying critical variables such as individual incremental recovery, on the aggregate results.

4.6.3 Inflation

A general increase in the price level affects selling prices, costs, and interest rates. Thus project analyses are not affected unless these elements change at different rates. This is illustrated by equations 6 and 7.

Net present value - with no inflation

17) $$NPV = \sum_{t=1}^{N} \frac{P_t q_t - TC_t}{(1+r)^{t-.5}}$$

Net present value - with inflation at rate, i

18)
$$NPV = \sum_{t=1}^{N} \frac{P_t q_t (1 + i_g)^{t-.5} - TC_t (1 + i_g)^{t-.5}}{(1 + r)^{t-.5} (1 + i_g)^{t-.5}}$$

where i_g is the general rate of inflation.

It should be obvious that in the second case the term $(1 + i)^{t-.5}$ could be cancelled out. Thus there is no real difference in the approaches from an analytical viewpoint. So, if we were evaluating a number of projects to determine their net present value, the effect of general inflation would be unimportant.[10]

Changes in relative prices are not so easily handled. They occur because of changing demand and supply relationships and although some average of all these changes is precisely what makes up the change in the 'absolute' price level (i.e., general inflation) it is quite possible that price changes in any industry could differ from the general rate of inflation quite significantly. This is really the essence of any forecasting problem, to forecast how costs in a specific industry and market prices of that industry's output will change. Any such changes must be explicitly included in the evaluation. Here we consider all values in real terms (that is, ignoring inflation). We allow for the more rapid increases in the price of oil that are likely (due both to the fact that oil is a depleting resource and to the influence of OPEC) by running the analysis at several different oil prices with costs kept constant.

4.6.4 The Discount Rate

The choice of an appropriate rate of interest with which to discount the future is a subject of considerable (and inconclusive) debate in economic literature (see Section 2.2.2 above). The issue revolves around the extent to which present generations should consider the welfare of future generations when making decisions about current investment projects. The problem can be characterized somewhat loosely as follows. Low discount rates may favour future generations by justifying high levels of current investment, the benefits of which will be realized in the future. High discount rates favour the present by discouraging investment, releasing current income for consumption purposes, the benefits of which are realized by today's consumers.

Some analysts prefer the use of some appropriate proxy for the spectrum of market interest rates since such a proxy rate would reflect the opportunity cost to private business of engaging in any investment activity. Others claim this rate, which must emerge from present generation decisions, is too high and is thus unfair to the future. They advocate the use of a lower 'social discount rate'. Without entering the debate further, we may reasonably allow for both points of view by including the discount rate as a parameter subject to some sensitivity analysis.

We have incorporated a private interest rate in real terms (that is abstracting from the rate of inflation) of 8 percent since that is an approximation of the historical rate of return earned in the oil industry. If we assume a rate of inflation of 7 percent, this translates into a nominal interest rate of 15 percent. Even this may appear a bit low to some under current conditions but it should be remembered that the rate also abstracts from some major risk considerations as discussed in Section 2.2.7 above. Furthermore, the rate is intended to approximate a long term situation not merely current conditions. We have also carried out the analysis using a zero rate of interest in deference to future generations. The lower rate should result in more tertiary recovery projects emerging as profitable ventures which presumably would increase the welfare of future generations by extending the time to total depletion of oil resources.

4.6.5 Reservoir Development Costs

The costs of production for each recovery process may be categorized as follows:

Capital Costs

- well drilling and completion costs
- injection and production well equipment costs
- capital equipment specific to a particular process such as steam generators for the steam drive and steam stimulation models and air compressors for the in situ combustion model

Operating Costs

- general well operation costs
- operating costs for equipment specific to particular processes
- overhead and administration costs

Costs of Materials

- costs of chemical used
- costs of miscible injection materials (i.e. CO_2)
- costs of water

In general, these costs of reservoir development depend on the location of the reservoir, the depth of the pay zone and the age of any still usable equipment on the site. Our cost information was built up in three areas of the province of Alberta, the foothills region, the northern region, and the plains region. Reservoir discovery years reported by ERCB allowed us to determine the likely age of capable wells in place which allowed us to make some assumptions about the proportion of wells that require workovers. Estimated development costs were obtained from the literature and from a number of cooperating equipment and material suppliers and oil companies active in enhanced recovery. The final cost estimates incorporated in the model were then circulated to a larger number of industry representatives and in some cases adjustments were made according to the comments received. The final estimates of costs used in the study are given in Appendix B.

All costs are levied against a particular project in the year in which they are projected to occur. Thus, if a reservoir is developed in several stages, capital costs will be allocated to several years of that project since each stage starts one year after the start of the previous stage.

Yearly revenue from a particular reservoir depends on the yearly production aggregated across all development stages. This amount is simply multiplied by the assumed price to get total revenue in each year. When tax and royalty considerations are included, the model calculates them according to the current federal and Alberta regulations outlined in Appendix C. It should be noted that whereas in practice corporate taxes would be calculated with due regard to a particular company's overall tax position, our calculation is made on a project-by-project basis and as such presents the maximum tax effect, that is, the possibility of writing off costs against other company income is assumed not to exist.

Treating each project as an independent operation and using only the Alberta provincial tax and royalty regulations undoubtedly distorts our results to some extent but nonetheless the exercise is interesting and informative.

Footnotes

[1] The basis of the estimating procedure and the definitions used by the Board are discussed in Alberta Energy Resources Conservation Board, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur at December 1976 (Calgary: Alberta Energy Resources Conservation Board, 1977), Report 77-18.

[2] See B. Agbi, "Enhanced Oil Recovery Potential in Alberta Sandstone Reservoirs" (Calgary: Petroleum Recovery Institute, May 1977), Interim Report IR-6.

[3] Lewin & Associates, Inc., The Potential and Economics of Enhanced Oil Recovery, prepared for the Federal Energy Administration, April, 1976.

[4] Ibid.

[5] The calculation utilizes a formula similar to our formula for calculating tertiary recovery

$$1) \quad Rw = \frac{Soi - Sor}{Soi}$$

where Soi is initial oil saturation
Sor is residual oil saturation after waterflood
Rw is recovery factor for primary and secondary recovery

But

$$2) \quad Soi = 1 - Sw$$

therefore

$$3) \quad Rw = \frac{1 - Sw - Sor}{1 - Sw}$$

Also

$$4) \quad R_t = \frac{\text{recoverable oil}}{\text{total oil in place}} = Rw \times R_c$$

where R_t is the total recovery factor
R_c is conformance (the proportion of the reservoir contacted by the waterflood).

Using some general averages for Alberta, based on discussion with ERCB staff and internal reports, $R_t = 0.38$, $Sw = 0.17$, and $Sor = 0.33$, we can calculate Rw as 0.60 from 3) and R_c as about 0.63 from 4).

Since the general average used includes reservoirs that are on primary production only, this number is fairly conservative. In addition, we are concerned here only with the better pools in the province (since many of the poorer ones have been screened out). Thus we are not being overly generous in assuming that the overall sweep efficiency is approximately 70 percent.

[6] There is, however, another aspect of this problem that perhaps should be taken into account. The reduction in residual saturation due to some tertiary process, say steam displacement, may depend on the initial saturation when the process was initiated. If we start with 50 percent residual saturation, we might reduce it to 20 percent, whereas, other things equal, an initial residual saturation of 25 percent would yield zero incremental recovery (in other words saturations would not be reduced at all) because of the mechanics of steam displacement. This possibility was considered in the screening process by eliminating reservoirs with low residual oil saturations (less than 30 percent) after the current recovery scheme.

[7] C. R. Smith, *Mechanics of Secondary Oil Recovery* (Huntington, New York: R. E. Krieger Pub. Co., 1966).

[8] P. G. Bradley, *The Economics of Crude Petroleum Production* (Amsterdam: North-Holland, 1967), ch. 2. Bradley cites previous applications of this type of cost measure: T. Marschak, "Capital Budgeting and Pricing in the French Nationalized Industries," *Journal of Business* 33, Jan. 1960, p. 202, and J. Hirshleiffer and J. DeHaven, "Feather River Water for Southern California," *Land Economics* 33, August 1957, p. 202.

[9] Lewin and Associates, Inc., *The Potential and Economics of Enhanced Oil Recovery*, p. v-10.

[10] If instead we set the equations equal to zero and solve for the internal rate of return, then 17 would yield a real rate, r, and 18 would yield a nominal rate,

$$\rho = r + i_g + ri_g$$

The ri_g term is small and usually ignored so we say that the nominal rate of return is simply the real rate plus the rate of inflation. Since revenues and costs are also increasing by the inflation factor, ranking of projects should be unaffected by general inflation. This discussion shows clearly that general increases in prices can have no effect on project ranking by net present value (although resulting rates of return need to be carefully interpreted in the presence of inflation).

CHAPTER 5

RESULTS OF THE ANALYSIS--POTENTIAL AND COSTS

5.1 Canadian Potential

The detailed simulation models were run on the Alberta reserves base. Canadian potential was extrapolated from these results by methods explained in Appendix A. The procedure essentially applied average recovery factors for process groups that emerged from the detailed Alberta analysis to the amount of oil in other provinces that might reasonably be expected to be candidates for those groups. The procedure took into consideration whether the oil was in sandstone or carbonate reservoirs and whether it was light-medium or heavy.

For example, Saskatchewan's 10.5 billion barrels of original oil in place is about 5.1 billion barrels heavy (less than 25° API) and 5.4 billion barrels light-medium (greater than 25° API).

The heavy oil amount was reduced first by assumed projected primary production of 7 percent (see Appendix A). The result was further reduced by 32 percent since this was the average amount that failed successfully to complete the screening in Alberta. The average thermal recovery factor of 0.388 was then applied yielding the estimate of technical recovery for heavy oils in Saskatchewan. This amount was further reduced by 17.2 percent, the percentage of technically amenable heavy oil that was not economic in the equivalent Alberta base case. The procedure was then repeated for the 5.4 billion barrels of light-medium oil except that this was first divided according to whether it was located in sandstone or in carbonate reservoirs since the average recovery factor differs in the two types of formations.

The average recovery factors used are as follows:

Thermal	0.388
Chemical	0.176
Miscible (sandstone)	0.154
Miscible (carbonate)	0.199

These are the actual recovery factors that emerged from the application of the models to Alberta reservoirs.

This procedure was applied to Saskatchewan, British Columbia, and all other provinces combined with results as shown in Figure 5.1. Enhanced oil recovery, given current technology, current taxes and royalties, assuming a $20 per barrel oil price and allowing industry an 8 percent real return, could contribute 4 billion barrels of oil to Canadian supplies. This represents a 67 percent increase over what would be available in Alberta alone, which may seem surprising since Alberta accounts for approximately 72 percent of the oil in Canada. The explanation lies in the preponderance of heavy oil in Saskatchewan which exceeds even that in Alberta. Heavy oil reservoirs are potentially very productive in tertiary applications, and Saskatchewan can expect to recover a billion barrels from these resources. The breakdown by province of original oil in place and projected incremental recovery is provided in Table 5.1.

The composition of this production is quite different from that in Alberta. As will be seen in the next section, the Alberta composition is miscible 78 percent, thermal 17 percent, and chemical 5 percent. The composition of production in the rest of the country will be closer to thermal 66 percent, miscible 34 percent, and chemical 0.5 percent. This makes the overall percentage shares for Canada become miscible 61 percent, thermal 36 percent, and chemical 3 percent.

FIGURE 5.1: Tertiary Recovery Potential in Canada (billion bbl)

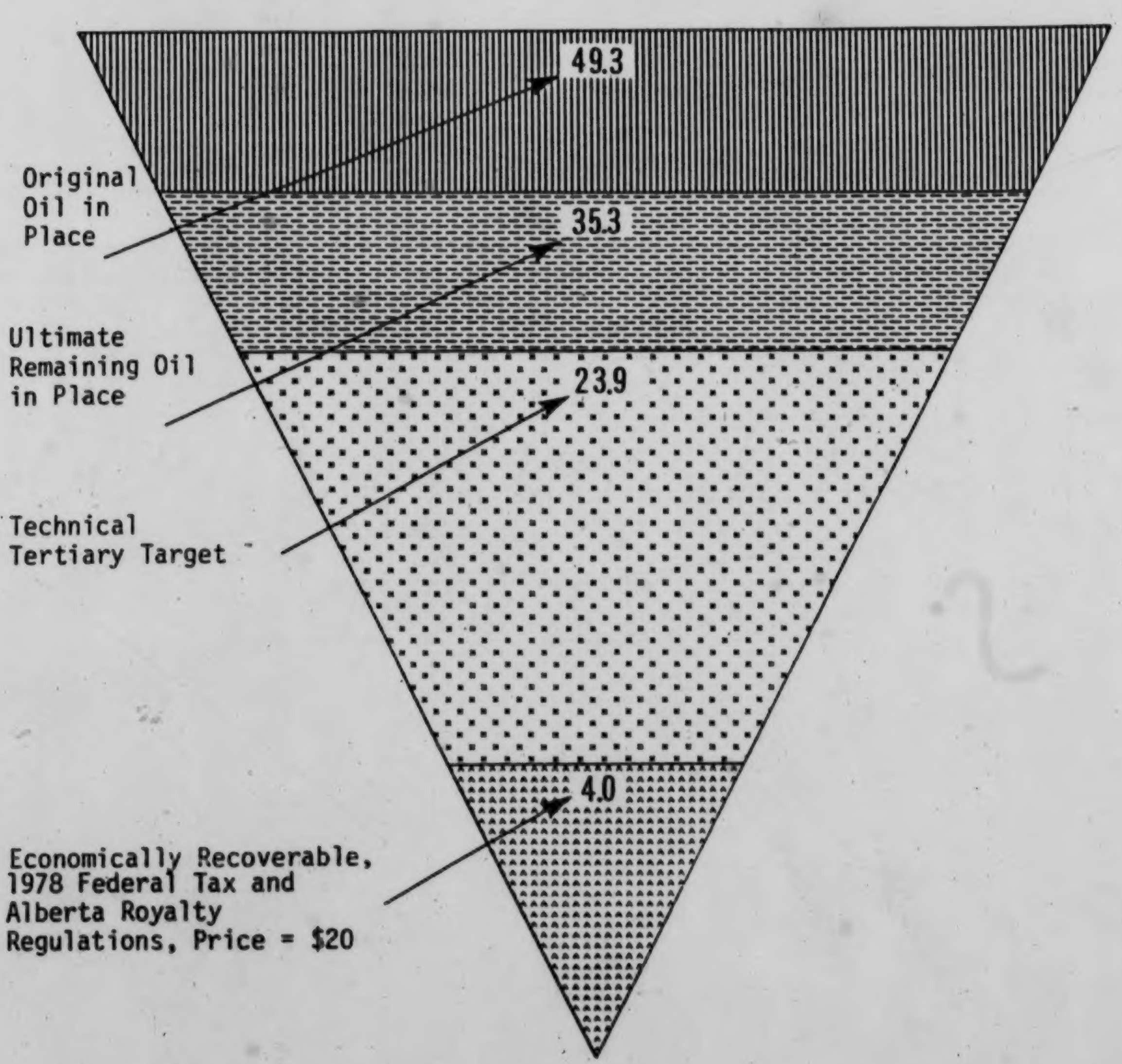


TABLE 5.1

ORIGINAL OIL IN PLACE AND PROJECTED TERTIARY RECOVERY BY PROVINCE AT $20/BBL
(billions of barrels)

	Alberta			Saskatchewan			British Columbia		Other[a]		Total[b] Canada
	Heavy	Light-Medium Sandstone	Light-Medium Carbonate	Heavy	Light-Medium Sandstone	Light-Medium Carbonate	Light-Medium Sandstone	Light-Medium Carbonate	Light-Medium Sandstone	Light-Medium Carbonate	
Original Oil in Place Dec.31, 1976	4.1	15	17	5.1	0.6	4.8	0.8	0.6	0.7	0.7	49.3
Projected Incremental Recovery Price = $20/bbl Discount Rate = 8% (real)	0.4	1.17	0.83	1.04	0.04	0.32	0.05	0.04	0.04	0.05	4.0

SOURCE: Appendix A

[a] Includes Manitoba, Territories, Ontario, and other eastern Canada.

[b] May not add due to rounding.

The potential contribution of enhanced recovery to daily production rates in Canada is illustrated in Figure 5.2. This figure is adapted from the National Energy Board publication Canadian Oil, Supply and Requirements, September 1978. As indicated in the figure, the lower area represents basic established production from conventional reserves, pentanes plus reserves, and oil sands. To this was added their estimate of likely additions to production from new discoveries, infill drilling and improved recovery. This was the N.E.B. base case estimate of future producibility and appears on Figure 5.2 as NEB base case (there is also a high and a low forecast but these are not reported here.)

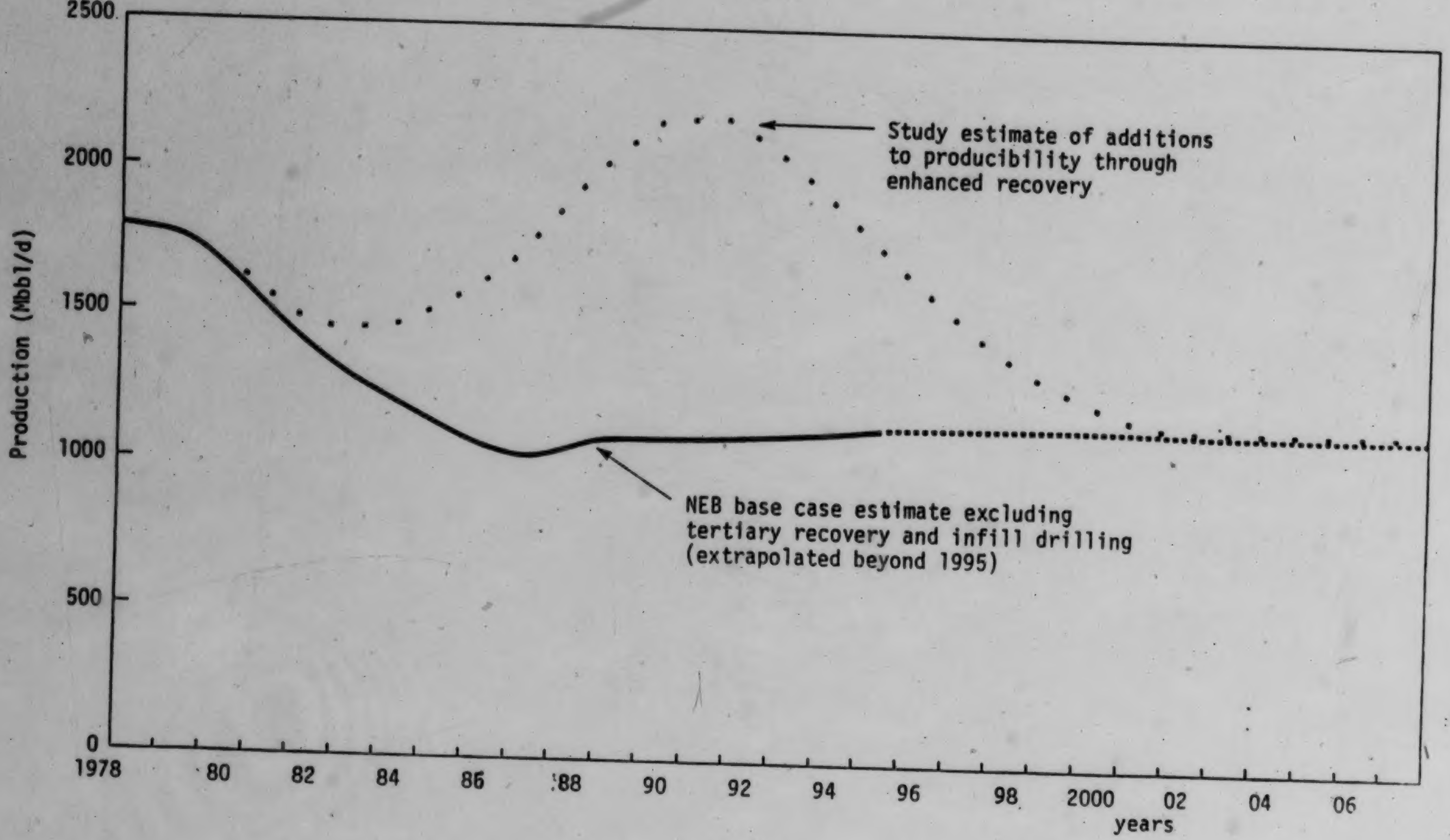
We adapted the NEB base case by subtracting the Board's estimate of additions due to tertiary recovery and infill drilling and adding our own.[1] This is shown on the diagram as the study producibility forecast.

Our base case forecast is seen to exceed that of the Board over most of the period shown and to make a significant contribution to the indicated requirements for crude oil and equivalent.

5.2 Alberta Potential

The procedures outlined in the previous chapters were applied to 1,372 individual reservoirs listed in Alberta's ERCB Report 76-18. The screening procedure eliminated 729 reservoirs from consideration as being either technically unsuitable to enhanced recovery or, while technically suitable in general, not amenable to any of the eight processes under consideration here. But since this procedure also allocated each reservoir to as many processes as were technically applicable, our analysis began with some 1,536 projects of which 951

FIGURE 5.2: Potential Contribution of Enhanced Recovery to Canadian Oil Production.



were profitable under the base case assumptions. The base case assumptions are an oil price of $20 per barrel, an 8 percent real discount rate, and current federal and Alberta tax and royalty regulations.

Many of the 951 profitable projects involved the application of more than one process to individual reservoirs. Therefore, the next step was to reduce the data base by allocating each reservoir to the single process for which it appeared most profitable (had the highest net present value). This reduced the number of projects to 643 individual reservoirs, of which 460 were profitable (had a net present value greater than zero after taxes and royalties). The breakdown of these projects by process is given in Table 5.2.

TABLE 5.2

ALLOCATION OF RESERVOIRS TO ECONOMICALLY DOMINANT PROCESSES
USING NET PRESENT VALUE UNDER BASE CASE ASSUMPTIONS
(number of reservoirs)

Process	Technically Amenable	Technically Amenable & Profitable	Economically Dominant[a]	Dominant & Profitable
Chemical				
Alkaline	119	92	82	75
Polymer	197	118	52	29
Microemulsion	148	25	17	6
Miscible Gas				
Hydrocarbon	500	368	337	210
Carbon dioxide	500	296	109	99
Thermal				
Steam drive	2	2	2	2
Steam cycle	5	5	1	1
In situ combustion	65	45	43	38
Total	1,536	951	643	460

[a] A process is economically dominant over another process that is technically possible in the same reservoir if it has a higher net present value (which may be negative, in which case the dominant process is not profitable).

Profitable projects were then ranked by net present value (NPV) and initiated on an assumed schedule that started 4 percent of the projects each year for 4 years and 14 percent each year for 6 years. Thus, all projects are on stream within 10 years with the lower rate of starts in the early years intended to allow industry some learning time. This schedule, though somewhat arbitrary, does not appear unreasonable and was derived from a basic assumption that all projects worthy of consideration would be underway by 1990. However, in order to see the effect of a more leisurely development schedule we also used an assumption of fewer starts per year with all projects being initiated over a 20 year period ending in the year 2000. This has no impact on the amount of oil recovered but does affect the rate of recovery and, because of the discounting procedure, all economic results. The results of this variation are reported in Section 5.2.3.

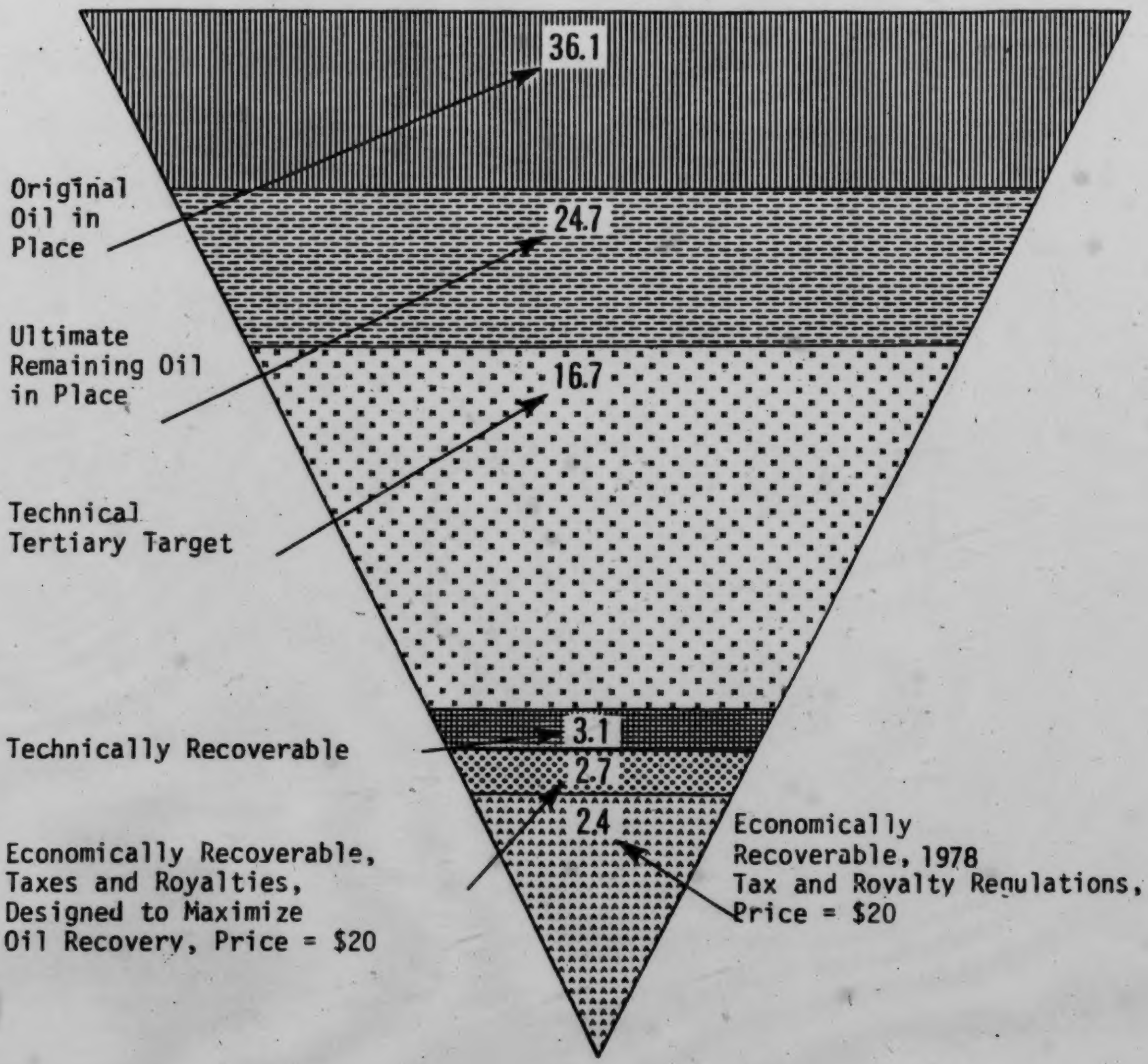
5.2.1 The Alberta Base Case Results

Oil price = $20/bbl
Tax and royalty = current federal and Alberta
Costs = basic estimate
Discount rate = 8 percent (real)

The triangle in Figure 5.3 presents the base case results. It is drawn approximately to scale by area, the overall triangle representing original oil in place of 36.1 billion barrels. This is the ERCB estimate for 1976 and does not include the major potential from the West Pembina region.[2]

The next contained triangle represents oil remaining after ultimate production by primary and secondary methods. The Alberta Energy Resources Conservation Board's 1976 estimate of 11.4 billion barrels recoverable represents an overall recovery of 31.6 percent and

FIGURE 5.3: Tertiary Recovery Potential in Alberta (billion bbl)



implies an ultimate remaining oil in place of 24.7 billion barrels. About one third of this is in reservoirs that under current technology would not be considered likely targets for enhanced recovery. The other two thirds (16.7 billion barrels) is the tertiary target, the ultimate remaining oil in place in all reservoirs that successfully qualify under the screening procedure.

Only a portion of this target will be recoverable. If costs are ignored the technically recoverable portion amounts to approximately 3.1 billion barrels. However, under our $20 base case assumptions, which include current tax and royalty regulations, we can only expect to recover 2.4 billion barrels. This is 14.7 percent of the target and represents an increase in the Board's estimated overall recovery of 6.6 percent (from 31.6 percent to 38.2 percent).

Current tax and royalty regulations make some marginal reservoirs unprofitable from a private viewpoint. By selectively reducing the tax take on these poorer prospects to make them profitable from the company viewpoint, the government could coax out a maximum of 300 million barrels more. This would involve complete removal of taxes and royalties for some of the least desirable projects. Further increases in recovery would require increases in the price of oil or reductions in production costs but the maximum attainable under current technology is the 3.1 billion technically recoverable amount.

Shares of recovery by process

Figure 5.4 illustrates the proportion of the 2.4 billion barrels that is attributable to each of the processes. Under the assumptions used in our base case estimate, the miscible gas processes appear the most promising followed by thermal and finally chemical processes. This is in part explained by the fact that a larger proportion of reservoirs meet the requirements of the screening procedure for the miscible gas process than for the others. Of the 1,536 projects under initial consideration, 65 percent were miscible gas, 30 percent were chemical, and 5 percent thermal.

The result is also due to the better economics of the miscible gas processes. Of the 460 profitable projects that emerged from the analysis, 67 percent were miscible, 24 percent chemical, and 9 percent thermal. The thermal share of actual oil recovery turns out to be larger than the chemical share because the 'target' in heavy oil reservoirs is significantly larger due to the very small percentage of primary and secondary production.

Rates of production

The rate of production of the incremental oil is indicated in Figure 5.5. The contribution to daily production rates peaks in 1992 at 656 Mb/d (240 MMb/yr). The average production rate over the 28 year development period is about 235 Mb/d. This would be a significant contribution to the 1.8 to 2.3 MMb/d forecast as the total requirements for crude oil and equivalent between 1978 and 1995 by the National Energy Board.[3]

The share of chemical, thermal and miscible groups in cumulative production over time is presented in Figure 5.6. The diagram provides a forceful illustration of the relative importance of the three process groups in ultimate production. It also provides, to some extent, a visual illustration of the general timing of ultimate production. Thermal processes come on stream first but are quickly overtaken in volume by miscible processes. Chemical production makes its contribution somewhat later in the development period.

FIGURE: 5.4: Percentage of Total Recovery Attributable to Each Process

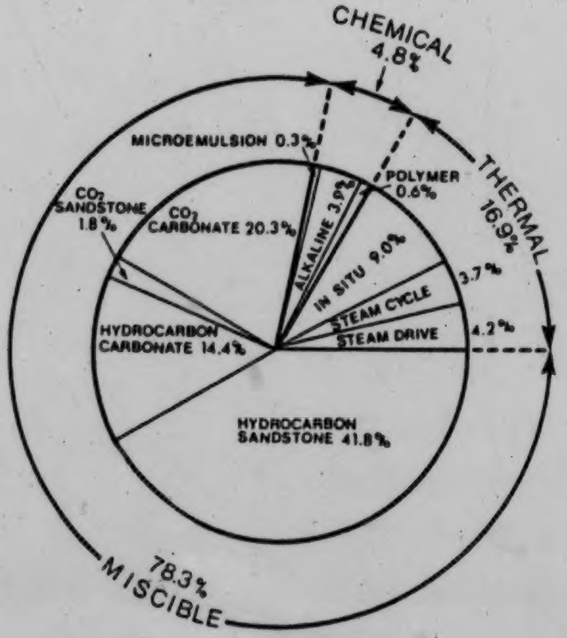


FIGURE 5.5: Tertiary Production Rate Forecast (base case).

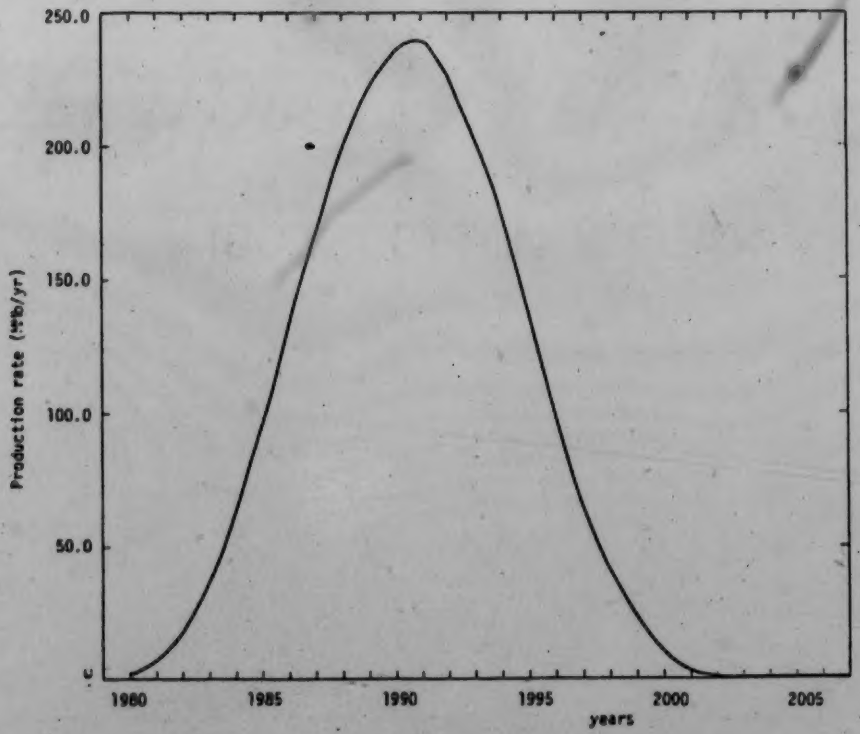
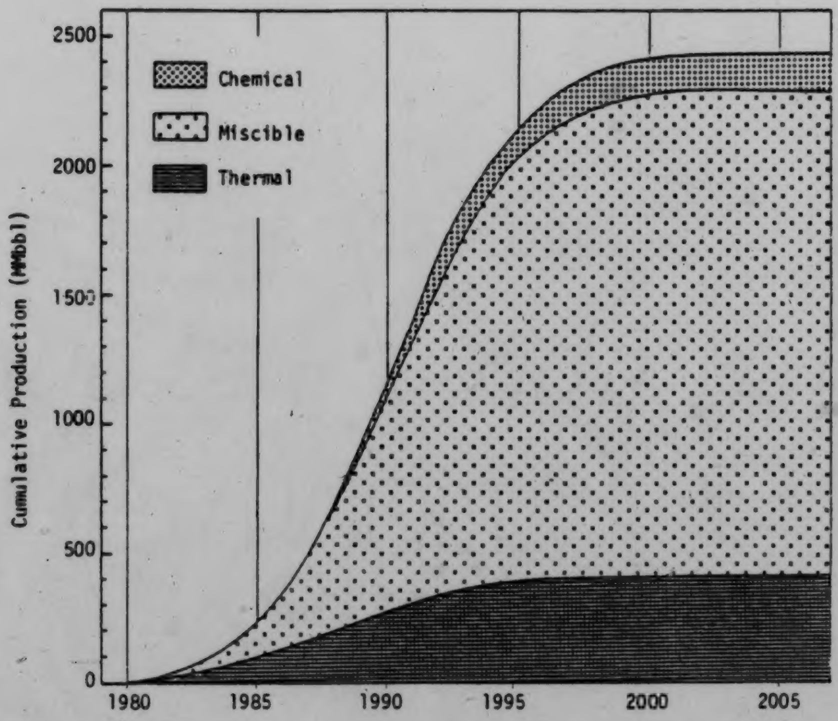


FIGURE 5.6: Distribution of Cumulative Production by Tertiary Recovery Process



Costs of tertiary recovery

The specific cost items applied to each project are set out in Appendix B. These items are classified as either capital, operating, or material costs.

Figures 5.7 to 5.14 portray the relationship among the various categories of costs involved in the production of tertiary oil. In the figures showing cost flows per year we have added operating costs and costs of materials together and classified them as variable costs of production. These variable costs are seen to be much more significant than capital costs in the overall cost pattern. Our classification does not necessarily correspond with what industry commonly refers to as 'front end' costs since that term lumps capital and material costs together on the grounds that material costs (chemicals, cost of water and fuel for production of steam, etc.) generally precede actual production and, therefore, are properly referred to as being at the front end of the development process. However, material costs do vary over time in the individual production process and although our models do not allow for this, the amount of materials used is related to associated current production which qualifies them as variable costs in the view of the economist.

Undiscounted total costs of $29.4 billion (in 1978 dollars) are composed of capital costs ($3.6 billion), operating costs ($10.1 billion), and materials costs ($13.5 billion) plus a calculated residual for overhead and administration and risk considerations of $2.2 billion. Discounting at 8 percent translates the costs into a present value of $16 billion.

FIGURE 5.7

UNDISCOUNTED COSTS BY CATEGORY
ALL PROCESSES (BASE CASE)

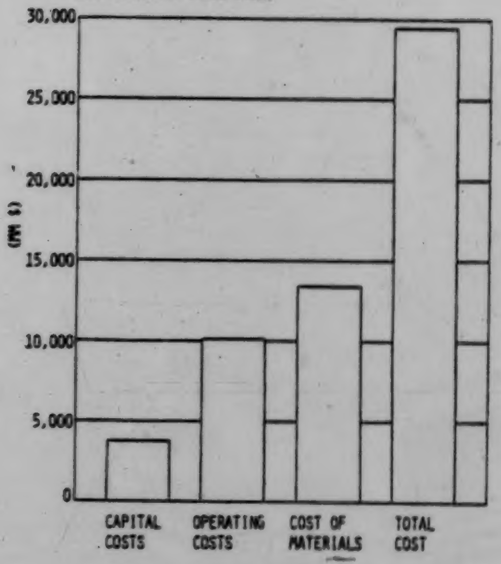


FIGURE 5.8

TOTAL COST BREAKDOWN, ALL PROCESSES
BASE CASE

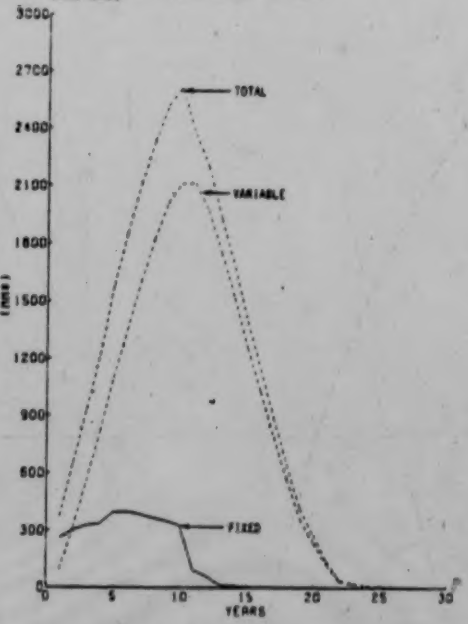


FIGURE 5.9

UNDISCOUNTED COSTS BY CATEGORY
THERMAL PROCESSES (BASE CASE)

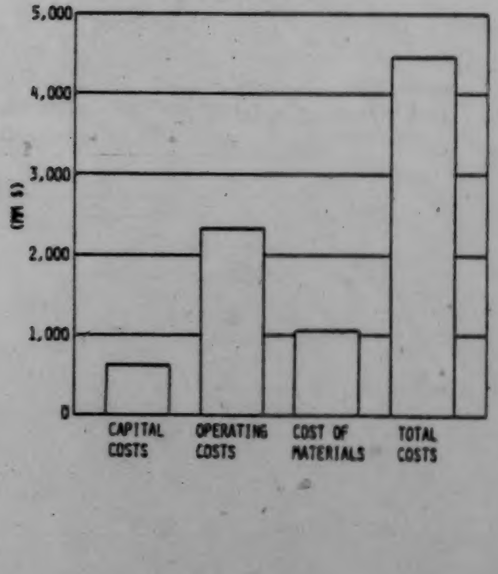


FIGURE 5.10

TOTAL COST BREAKDOWN, THERMAL PROCESSES
BASE CASE

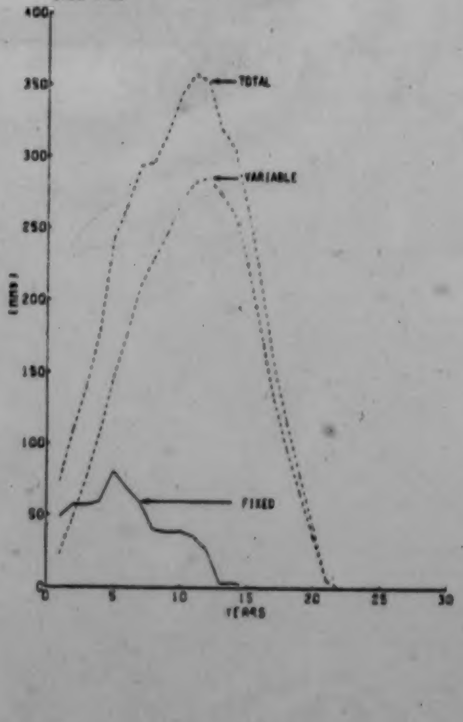


FIGURE 5.11
UNDISCOUNTED COSTS BY CATEGORY
CHEMICAL PROCESSES (BASE CASE)

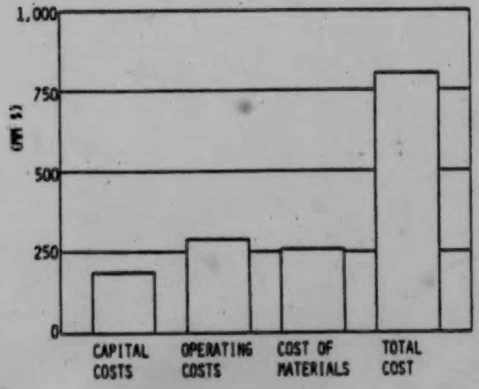


FIGURE 5.12
TOTAL COST BREAKDOWN, CHEMICAL PROCESSES
BASE CASE

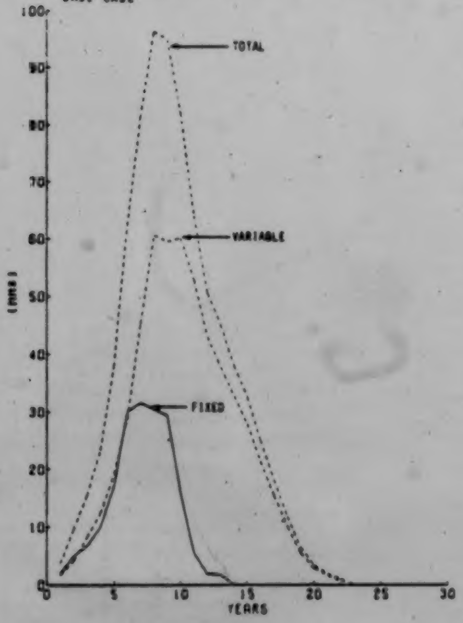


FIGURE 5.13
UNDISCOUNTED COSTS BY CATEGORY
MISCIBLE GAS PROCESSES (BASE CASE)

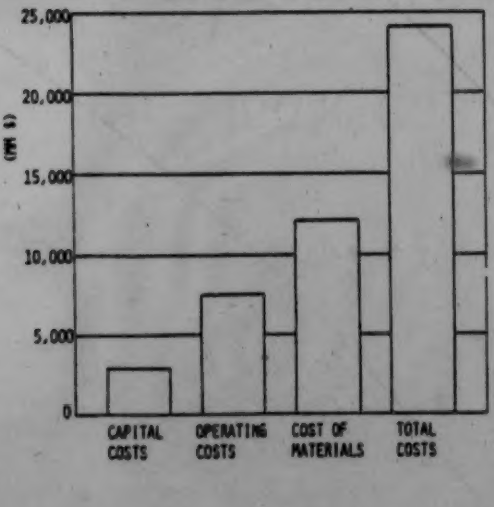
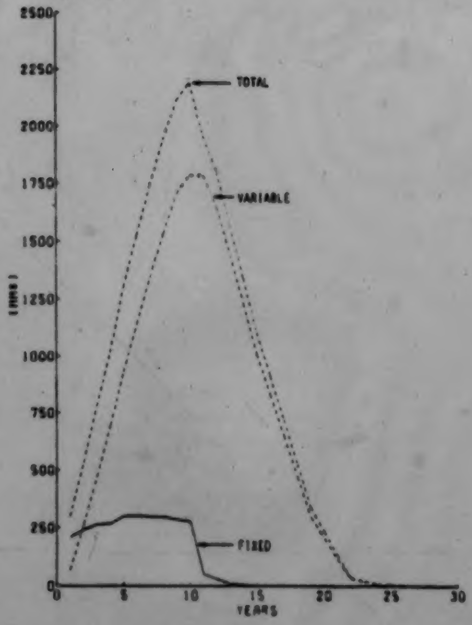


FIGURE 5.14
TOTAL COST BREAKDOWN, MISCIBLE GAS PROCESSES
BASE CASE



The cost classification for individual processes is presented in the next chapter (section 6.2). The categorization of costs in the chemical and miscible processes is interesting but unremarkable. However, the thermal category requires some comment since it introduced a bias into the analysis. The bias occurs because of the manner in which overhead costs are calculated as a percentage of capital and operating costs. Four percent of capital costs and 20 percent of operating costs were used as a standard estimate of overhead costs in all models. These were calculated as a residual element and added to total costs. The capital cost component of each project, as discussed in Appendix B, refers to fixed equipment (generators, wellsite equipment, etc.) and drilling costs and is consistent over all processes. In the thermal processes a problem arises over whether the fuel costs required to generate steam or compress air should be allocated as an operating cost or as a material cost, i.e., a cost of introducing required material (steam or air) into the reservoir. This was an important decision since these fuel costs are a very large proportion of the total costs in the thermal processes. We decided to allocate them as a materials cost since that would preclude them from being incorporated in the overhead calculation (20 percent of operating costs only) and thus prevent inordinately higher overhead charges being assessed against thermal projects relative to chemical and miscible projects. In the steam case we allocate these costs to the materials category and such costs therefore do not impact on overhead charges.

In the in situ combustion case, on the other hand, the fuel requirements for air compression were inadvertently allocated to operating costs which meant that an additional 20 percent of these costs (for overhead) was added to total costs. This overhead charge turned out to be much higher per project than that used for the other processes and we judged it to be a source of some bias against the in situ process. This was a potentially serious oversight in the analysis which did not become apparent until all sensitivity runs were completed. An adjustment similar to that for the steam process would have required a considerable cost of time and resources in order to repeat the entire set of sensitivity analyses. Fortunately, there is an offsetting factor in thermal generation that permitted a less drastic reconciliation of the problem. The offsetting factor is the upgrading costs which are required to make heavy oils comparable in quality to other oils. The problem and its reconciliation are discussed in detail in the thermal section of the report. The net impact was an underestimation of potential incremental recovery of just less than 4 percent (about 100 million barrels).

Costs and supply

The relation between price and incremental recovery is shown in Figure 5.15 which relates incremental supplies of oil due to enhanced recovery to the 'supply price' associated with that oil. The figure was drawn by ranking all reservoirs in ascending order of supply price (the average price per barrel of oil sold that is required to recover all costs of producing that oil). Increasing prices bring marginal reservoirs into production at the point where the expected market price over the development period is equal to or greater than the 'supply price', our calculated break even cost per barrel. Break even is used here in the sense of the economist, it includes a return to capital and compensation for entrepreneurial risk. The solid line is the 'real' supply curve based only on actual costs of production (including returns for capital and risk). The dashed line incorporates taxes and royalties into the calculation (for a $20 price of oil) and indicates the break even cost including this payment to governments. It merges with actual resource costs after the supply price reaches about $20 per barrel because in that case there would be no accounting profit and therefore no taxes (although royalties are positive for slightly higher prices since they are based on gross revenue not profit).

Figure 5.15 thus presents a relation that is very close to the notion of a supply curve in economics. The standard supply curve indicates the quantity of any commodity that will be supplied to the market at various prices when other influences on this quantity are assumed to be unchanging. The supply curve is based on incremental (marginal) costs of production which are generally assumed to increase as production increases. That means that higher prices are usually required to bring forth larger quantities of output. That is precisely the situation depicted in Figure 5.15 except for one important qualification. The supply price used in the figure is really an average cost per barrel over the entire period of development of particular reservoirs (which ranges from 7 to 21 years). Movement from one actual supply price on the curve to the next higher one brings an addition to economic reserves. This addition is not immediately available but will be made available over some time period. The process is not a continuing one because we are dealing with a declining resource. That is, by the time some high cost reservoirs are able to be brought on stream many low cost ones will be in the last stages of production. This is in contrast to the supply curve for produced commodities wherein a given price induces production of some quantity in perpetuity, as long as other things remain constant. Nonetheless,

FIGURE 5.15

REQUIRED COST PER BARREL OF ADDITIONS TO PETROLEUM RESERVES THROUGH ENHANCED OIL RECOVERY

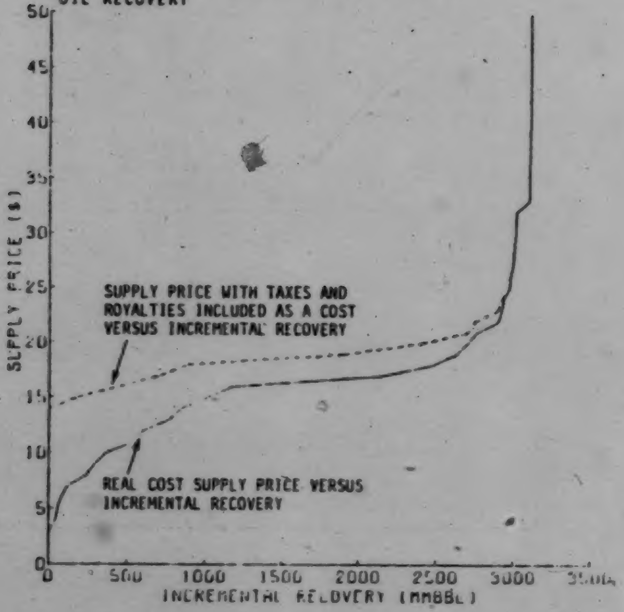
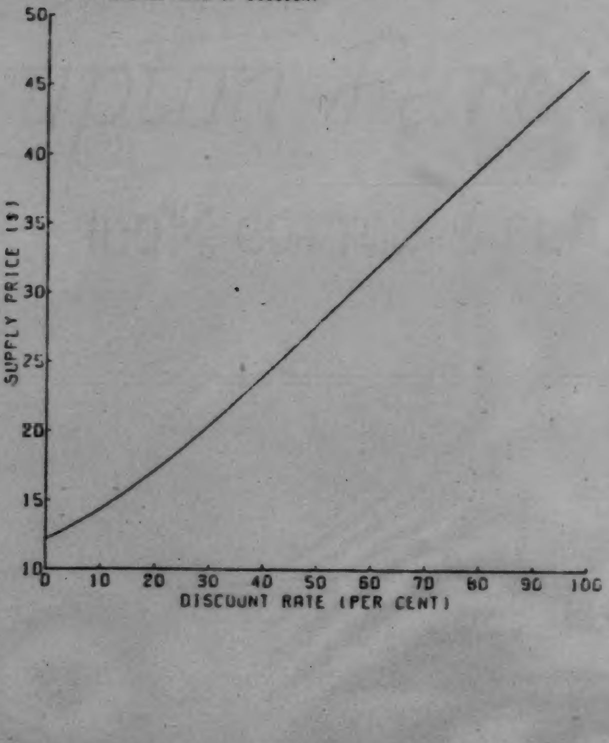


FIGURE 5.16

THE VARIATION OF OVERALL AVERAGE SUPPLY PRICE WITH ASSUMED RATE OF DISCOUNT



the curve in Figure 5.15 is useful in that it illustrates the ultimate amount of oil that may be expected from enhanced recovery as increasing levels of cost per barrel become acceptable due to rising market prices. However, the ceterus paribus (other things equal) warning is particularly relevant here because the curves are based on a calculation of supply price for each reservoir using a discount rate of 8 percent (i.e., allowing industry an 8 percent real rate of return). If we had chosen to discount at a real rate higher than 8 percent, the curves in Figure 5.15 would be shifted upward since each project would require a higher price in order to cover the increased return required by industry. (This result is illustrated in the discussion of individual process results, for example alkaline flooding, in Section 6.2). The impact of varying the discount rate on the calculation of the overall average supply price ($13.92) for the base case set of qualifying reservoirs is illustrated by Figure 5.16. Using a zero discount rate (implying no return for industry) would reduce the supply price to $12.22. A 15 percent discount rate, on the other hand, implies a supply price of $15.74.

Economic evaluation

Table 5.3 summarizes the private economic implications of full scale tertiary development of 2.4 billion barrels under the base case assumptions over the time period (28 years) during which development takes place. The net value to industry (in 1978 dollars) after taxes and royalties is $2.45 billion, almost 60 percent of which is attributable to the miscible gas processes. The average price per barrel required to recover all development and operating costs is $13.90. This is the 'supply price' defined formally in Section 4.6.

TABLE 5.3

SUMMARY OF BASE CASE ECONOMIC RESULTS[a]
(projects initiated over 10 years)

	Net Present Value ($MM)	Supply Price[b] ($)	Internal Rate of Return (%)	Forecast Incremental Recovery (MMbbl)
Aggregate tertiary activity	2,450	13.90	17	2,407
Thermal processes	756	10.50	131	407
Chemical processes	255	7.90	37	115
Miscible processes	1,439	15.20	13	1,885
Thermal				
Steam drive	254	7.20	75	90
Steam stimulation	327	10.20	176	101
In situ combustion	175	12.10	-	216
Chemical				
Polymer	23	12.70	30	15
Alkaline	229	6.60	41	93
Microemulsion	2	17.70	10	7
Miscible gas				
Hydrocarbon miscible	1,124	15.30	14	1,352
Carbon dioxide miscible	315	15.00	12	533

[a] Oil price $20/bbl, real discount rate 8%, current taxes and royalties, thermal upgrading costs not included.

[b] Rounded to nearest 10 cents.

It ranged from \$1.76 per barrel for a particularly good pool in the hydrocarbon miscible group to a high of \$96.05 per barrel for one of the polymer projects.[4] The averages given in Table 5.3 are weighted averages for profitable pools only, that is, pools for which the supply price is less than the assumed market price (\$20 per barrel in the base case).

The relatively low supply price of \$7.90 per barrel for the chemical group is interesting. This does not necessarily imply that costs of chemical recovery are significantly lower than others because the supply price for a particular reservoir depends on both costs and productivity. Productivity is a function of individual reservoir characteristics, not only the oil saturation, which partly determines incremental recovery, but also the permeability, pay thickness, oil viscosity, and pressure conditions, all of which determine the theoretical flow rate which may affect costs by requiring additional drilling. Thus, although it is true that the chemical processes do have a smaller initial capital requirement, this low supply price is also probably due to the generally higher quality of the particular reservoirs that emerged as both economically dominant and profitable.

Calculated internal rates of return (discounted cash flow rates of return) ranged from 0 to 176 percent. The rate for all the projects taken together is 17 percent. The thermal processes lead profitability by this measure with a rate of return of 131 percent. However, this calculation did not take into account upgrading costs so it is a somewhat unfair comparison.

The social value of tertiary recovery

The net value of tertiary recovery to Canada is potentially somewhat larger than has been heretofore indicated. From a social point of view, taxes should be irrelevant to the decision as to whether or not a project goes ahead. They should merely transfer some of the revenues from one subset of citizens to another. Therefore the potential value of tertiary recovery should be the net present value of all projects that are viable when no taxes are considered. Viable then means benefits exceed real costs of production regardless of how the benefits are distributed.

The rationale and application of the discounting procedure is also not straightforward from a social point of view. Whatever the rationale for discounting may be, its effect is to assign a higher value to the welfare of the current generation. There is some basis for this from the point of view of the individual but from the social point of view it is not clearcut, particularly when we are dealing with a depleting resource. The issue is complex, the subject of ongoing discussion in the literature of theoretical economics, and it is not our intent to delve into it further here. It is mentioned only to introduce Table 5.4, which illustrates some of the uncertainty in identifying the potential value to society of tertiary recovery.

TABLE 5.4
'VIABLE' RESERVOIRS AND POTENTIAL RECOVERY
FROM TERTIARY ACTIVITY

	Taxes & Royalties Not Considered Discount Rate			Current Tax & Royalty Considerations Incorporated Discount Rate		
	0	3	8	0	3	8
No. of viable reservoirs	544	523	484	530	504	460
Potential incremental recovery (MMbbl)	2,919	2,893	2,706	2,726	2,703	2,407

A discount rate of zero would reflect the view that the future is as important as the present. This view implies the largest number of viable reservoirs since future net benefits are not discounted. A 3 percent rate of discount, still quite low, would reflect some minimum risk-free return to the use of capital. The 8 percent rate adopted as our base case may be viewed as being composed of the risk-free return to capital plus a 5 percent component to allow for risk.[5]

To establish potential social value we must include all oil that could be profitably recovered without regard to the tax system. Within this category of Table 5.4 we then have to decide what rate of discount to consider. The higher the rate, the fewer the 'viable' projects in our list and thus the lower is our estimate of potential social value. We have adopted the conservative 8 percent rate to establish our potential value figure on the grounds that, although lower rates of discount may emerge victorious from the economic debate, the actual decision making of private companies will ultimately decide what reservoirs get developed.

On this basis we calculated the social value of tertiary recovery if all reservoirs which are profitable with no regard for taxes and discounted at a rate of 8 percent, ultimately come on stream. Four hundred and eighty four reservoirs would then yield 2.7 billion barrels of oil at a $20 per barrel price. Development of this oil would cost $18.7 billion and return $26.1 billion in revenue for a net social benefit to Canada of $7.4 billion. The social rate of return on this activity would be 29 percent, and the per barrel supply price would be $14.34.

These results may be compared to the realized social value under current tax and royalty regulations discussed in the previous section (i.e., only reservoirs profitable after taxes are considered). Four hundred and sixty reservoirs yield 2.4 billion barrels (an 11 percent reduction) at a cost of $16 billion and returning total revenue (before taxes) of $23 billion for a net social value of $7 billion. The social rate of return on this activity is, coincidentally, also 29 percent, but the supply price is reduced to $13.92 per barrel.[6] The lower supply price is attributable to the elimination of 24 higher cost (though viable) reservoirs by the tax system. The elimination of 300 million barrels of oil with a net value of $400 million to Canada is a measure of the real cost of the tax system as applied to these projects. Ideally the tax system should have no impact on the level of production but should merely redistribute the net social value of production away from producers to society as a whole. In actual fact part of the tax system is somewhat blunt in its impact with resulting real loss of output. This is illustrated in Figure 5.17. The extent to which redistribution can be accomplished without attendant reductions in real production may be viewed as a measure of the efficiency of the tax system. This will be considered further in the discussion on economic rent below.

Revenue shares

The realized present value of net revenue discounted at 8 percent is $7 billion. The after tax present value is $2.45 billion. So the company share (which is in excess of their 8 percent real rate of return) is 35 percent with the two levels of government collecting 65 percent of the discounted value of tertiary development.

Undiscounted revenue and tax figures yield a slightly different result. Total net revenue from the projects is $18.7 billion as shown in Figure 5.18. The corporate share of this is $8.3 billion, or 45

FIGURE 5.17
IMPACT OF THE TAX SYSTEM ON NET
SOCIAL VALUE OF TERTIARY RECOVERY

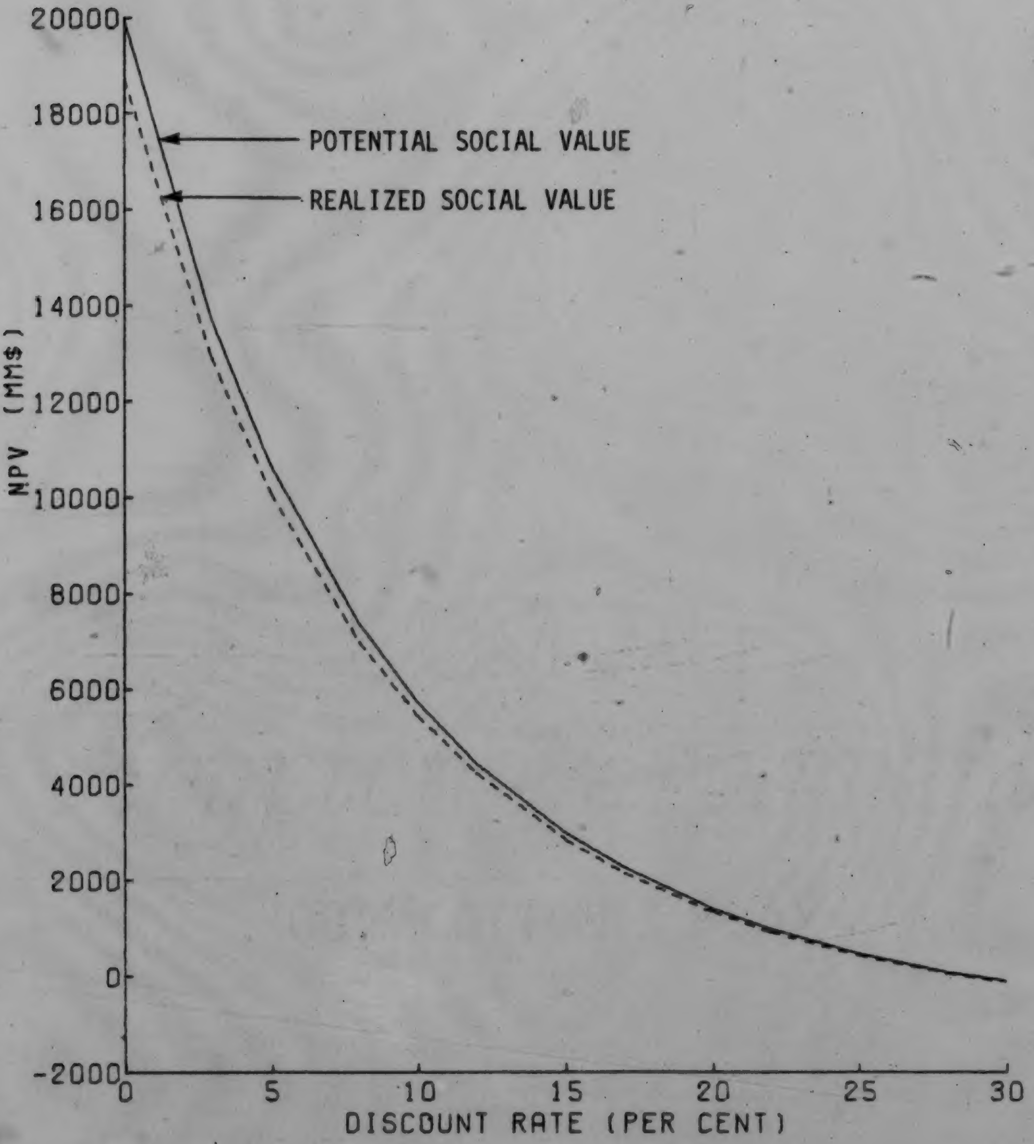
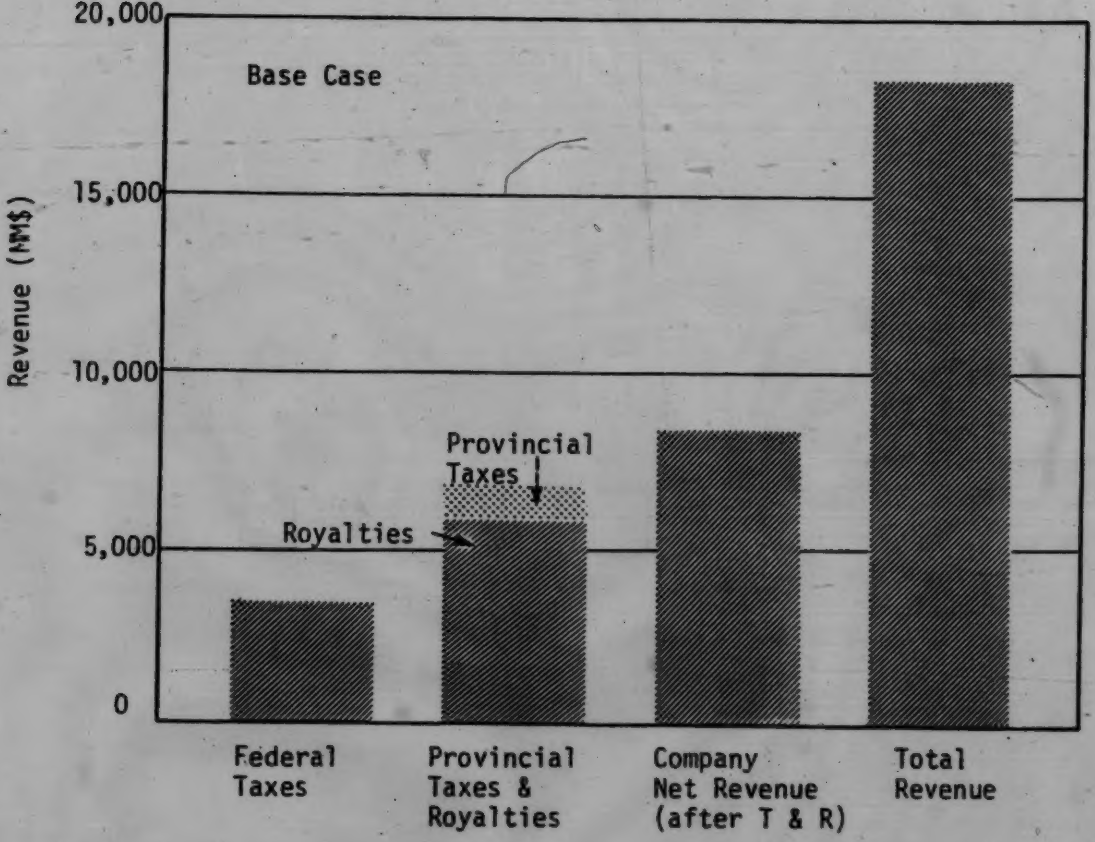


FIGURE 5.18: Shares of Revenue From Tertiary Recovery (not discounted)



percent. The total government share is $10.3 billion, or 55 percent. The federal government would collect $3.5 billion, or 19 percent, of the total while the provincial take is $6.8 billion (36 percent) about 85 percent of which is in the form of royalties.

Figures 5.19 to 5.22 show various flows of tax and royalty payments to the federal and provincial governments. The pattern of tax payments is skewed somewhat toward the latter half of the producing period. This reflects both the pattern of production and the fact that capital cost deductions are concentrated in the first half of the period.

Economic rent

Table 5.5 presents the revenue and tax figures for all processes in the base case. All revenues and costs are discounted at a real rate of 8 percent, which is approximately equivalent to a nominal rate of 15 percent, if we assume a rate of inflation of 7 percent per year.

TABLE 5.5

DIVISION OF NET REVENUES BETWEEN INDUSTRY AND GOVERNMENT
(base case)

	Total Net Revenue ($MM)	After Tax Net Revenue ($MM)	% of Total	Tax Take ($MM)	% of Total
All processes	7,005	2,450	35	4,555	65
Thermal	2,191	756	35	1,435	65
Chemical	677	255	38	422	62
Miscible	4,137	1,439	35	2,698	65

FIGURE 5.19

TAX PAYMENT BREAKDOWN. ALL PROCESSES.

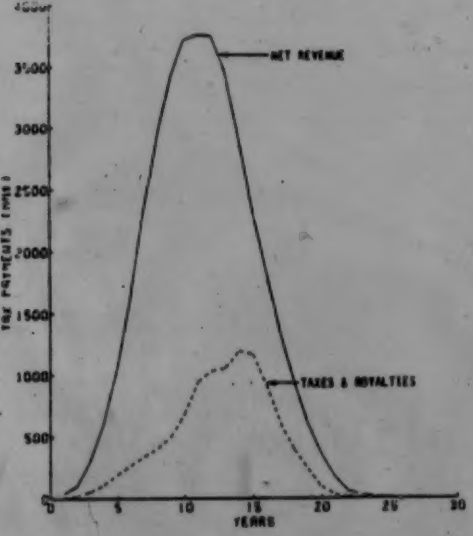


FIGURE 5.20

TOTAL TAX PAYMENTS (EPR) AND BREAKDOWN SHOWING FT, PT, AND ROY. FOR ALL PROCESSES. BASE CASE

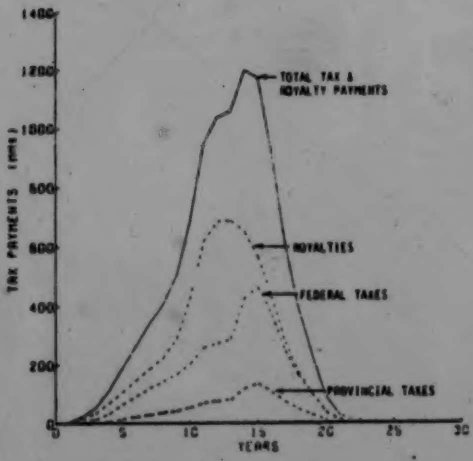


FIGURE 5.21

TAX PAYMENT BREAKDOWN. ALL PROCESSES. PROVINCIAL VERSUS FEDERAL REVENUES

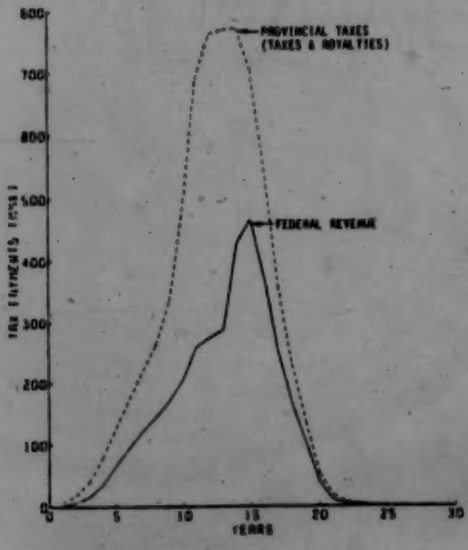
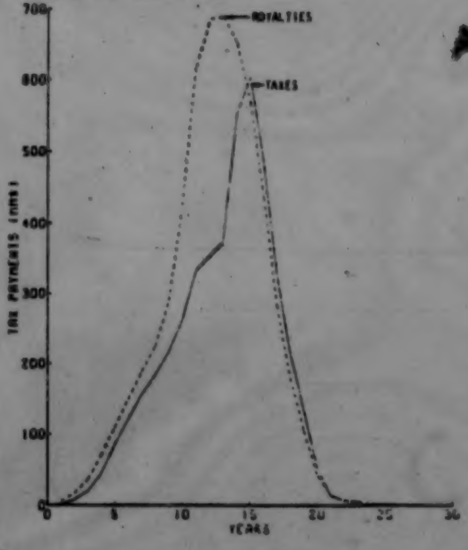


FIGURE 5.22

TAX PAYMENT BREAKDOWN. ALL PROCESSES. ROYALTIES VERSUS TAXES



If net revenue from tertiary recovery turned out to be zero, it would mean that the company was earning an 8 percent (real) return. Assuming that 8 percent (15 percent nominal) is sufficient to induce companies to engage in business activity (in particular tertiary recovery), the existence of positive net revenues would be an extra incentive, above what is required to induce the company to do business. Any such payment is known in economic terminology as 'economic rent'. It may be viewed as any payment to a firm in excess of the amount required to dissuade that firm from transferring its resources to some other activity.

From Table 5.5 we see that the economic rent is just over \$7 billion under our base case assumptions of \$20 oil price and 8 percent discount rate. Since by assumption companies are earning their required return (8 percent), this \$7 billion should accrue to the owners of the resource, freehold rights holders or the general public. A major problem of designing tax and royalty regulations is concerned with how to capture this 'rent' without interfering with the production process. This is a problem because the amount of rent depends on the productivity of individual reservoirs. If we design uniform regulations to maximize collection from highly productive reservoirs, less productive ones will be made unprofitable from the company viewpoint (i.e., they will be unable to earn their 8 percent) and will remain undeveloped. Another problem centres on the fact that the amount of economic rent depends on the assumed discount rate (industy's required rate of return). This is illustrated in Table 5.6 where it can be seen that the larger is the company's 'required' return, the smaller is the economic rent. The companies, however, receive a smaller share of this reduced 'rent' (from 45 to 13 percent in Table 5.6). Figure 5.23 shows

TABLE 5.6

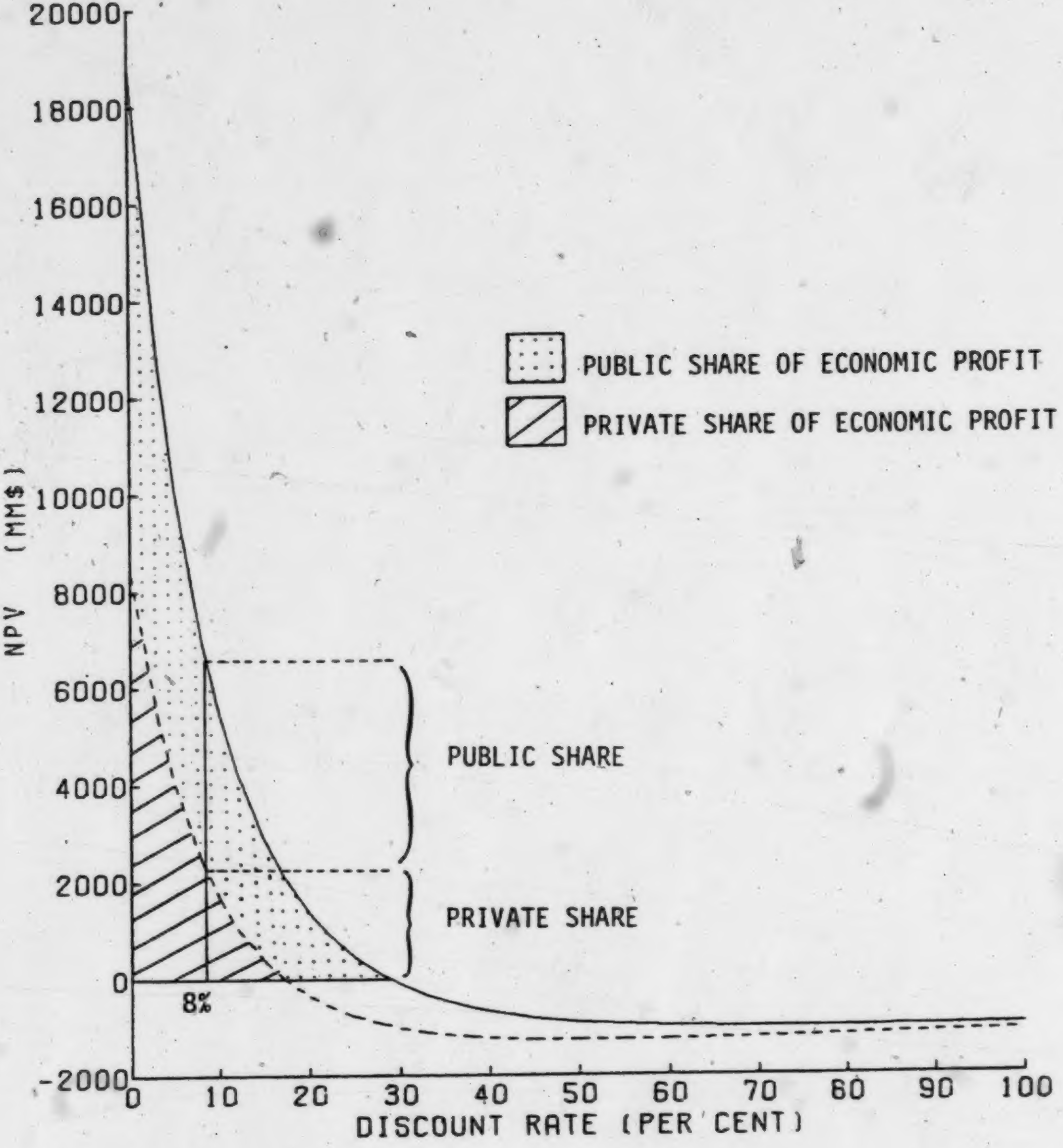
VARIATION OF SHARES OF REVENUE WITH DISCOUNT RATES

Discount Rate		Total Net Revenue	Company After Tax Net Revenue		Government Tax & Royalty Take	
(Real) (%)	(Nominal) (%)	(Economic Rent) ($MM)	($MM)	(% of Total)	($MM)	(% of Total)
0	(7)	18,736	8,385	45	10,351	55
3	(10)	12,921	5,441	42	7,480	58
8	(15)	7,005	2,450	35	4,555	65
12	(19)	4,251	1,067	25	3,184	75
15	(22)	2,863	379	13	2,484	87

NOTE: This table illustrates how the chosen discount rate, which is applied to actual revenues and taxes realized each year, affects both total net present value and the division of this value (net revenue) between industry and government. Higher discount rates may be interpreted as allowing industry a higher required rate of return. Given the same actual revenues and costs in all cases in the table, the surplus net revenue (that is, surplus to amounts required to keep industry resources in the business of enhanced recovery) is smaller because the required return is larger (essentially it becomes a component of costs). The actual dollars collected in taxes and royalties are the same in all cases but the present value of these amounts is smaller as the discount rate is increased.

FIGURE 5.23

DIVISION OF ECONOMIC PROFIT BETWEEN GOVERNMENT AND INDUSTRY AT VARIOUS RATES OF RETURN FOR INDUSTRY



the shares of net present value that accrue to government and industry. The industry share (of the economic rent) is seen to decline as the discount rate increases, disappearing completely at a real rate of approximately 15 percent which is roughly comparable to a nominal rate of 22 percent.

Economic rent per barrel can be inferred from a comparison of discounted average revenue per barrel (which is market price here since we assume price is constant over time) and discounted average cost per barrel (which is our supply price) where the latter is calculated with and without taxes and royalties included as a cost. The calculations described below are set out in Table 5.7. Since the calculation also incorporates the return required by industry, the 'economic rent' can be calculated as the assumed price of oil minus the supply price. For our base case, assuming all projects begin in the same year, the supply price is \$13.78 which with a \$20.00 price of oil implies unappropriated economic rent per barrel of \$6.22.[7] With only royalties added as a cost, the supply price becomes \$16.10 which means \$2.32 per barrel is captured by the royalty.

TABLE 5.7

ECONOMIC RENT PER BARREL
Base Case (\$20 per barrel)

Supply Price Based on Real Production Costs Only (SP)	Supply Price With Royalties Included as a Cost (SPR)	Supply Price With Royalties and Taxes Included as a Cost (SPRT)
13.78	16.10	17.84

Economic Rent per Barrel (Price-SP)	Rent Captured by Royalty (SPR-SP)	Rent Captured by Taxes (SPRT-SPR)	Non-Captured Rent (Company Surplus) (Price-SPRT)
6.22	2.32	1.74	2.16

Adding taxes as a cost causes the supply price to increase to \$17.84 which means another \$1.74 of the economic rent is captured by the tax levy. This leaves \$2.16 per barrel as non-captured economic rent left with industry. This is an amount over and above the return required to prevent firms from abandoning the activity. It is therefore 'economic rent' as discussed above.[8]

How to collect this \$2.4 billion (\$2.16 per discounted barrel) without hampering industry's recovery effort is a difficult problem because of the variability of the rent amount and distribution among reservoirs. For the most productive reservoir considered here a supply price of \$1.76 implies economic rent per barrel of \$18.24 of which \$12.57 (69 percent) is captured by taxes and \$5.67 (31 percent) is left for the operator. The poorest (yet marginally profitable) reservoir has a supply price of \$19.00 meaning rent of \$1.00 per barrel of which the tax system collects 83 percent and the company retains only 17 percent. A general set of regulations that successfully reduces the average amount per barrel left with the company will certainly make marginal reservoirs unprofitable and reduce the absolute amount of tertiary oil available to the country.

The company share of the excess revenue is from one point of view an extra incentive to engage in a relatively risky investment. There may be some justification of this view given the nature of the technological uncertainties which may not be adequately reflected by the structure of our models. Nonetheless the models do take account of risk both in a specific manner when it is incorporated in the estimate of overhead costs, and in general by way of a risk component incurred in the discount rate. Therefore, it is also possible to view the excess revenue as being 'left on the table' since industry would have been willing to undertake these projects anyway.

This tradeoff between rent collection and interference with the production process should be a major concern of all levels of government. Perhaps some consideration should be given to regulations geared to individual reservoirs so that the benefits of high productivity pools could be realized by their owners, the public, who would also be sharing some of the risks of low productivity reservoirs. This would involve costs for both governments and operators related to evaluation and administration. Care would have to be taken to ensure equity both in practice and in appearance. Industry would undoubtedly react adversely to the proposal both because of the increased 'red tape' and because of the significant potential reduction in their 'share' of the rent. However, if properly balanced by some method of increasing the share of risk borne by the public, such a system might turn out to be to industry's advantage.

5.2.2 The Impact of the Check on Production and Injection Flow Rates

As explained in Section 4.4.1, we incorporated a check to ensure that the flow rates of oil within each reservoir implied by the assumptions of the models did not exceed the maximum rate implied by the characteristics of each reservoir. This check was operative in 62 percent of the reservoirs. In these cases, injection and/or production wells required were increased by 20 percent adding substantially to development costs. In some cases the affected reservoirs remained profitable in spite of the higher costs but in other cases they were made unprofitable. In many cases the reservoirs affected were already unprofitable, but 84 reservoirs could have been profitable at a $20 price without the flow check and eliminating these reservoirs reduced our estimate of tertiary recovery by 300 million barrels.

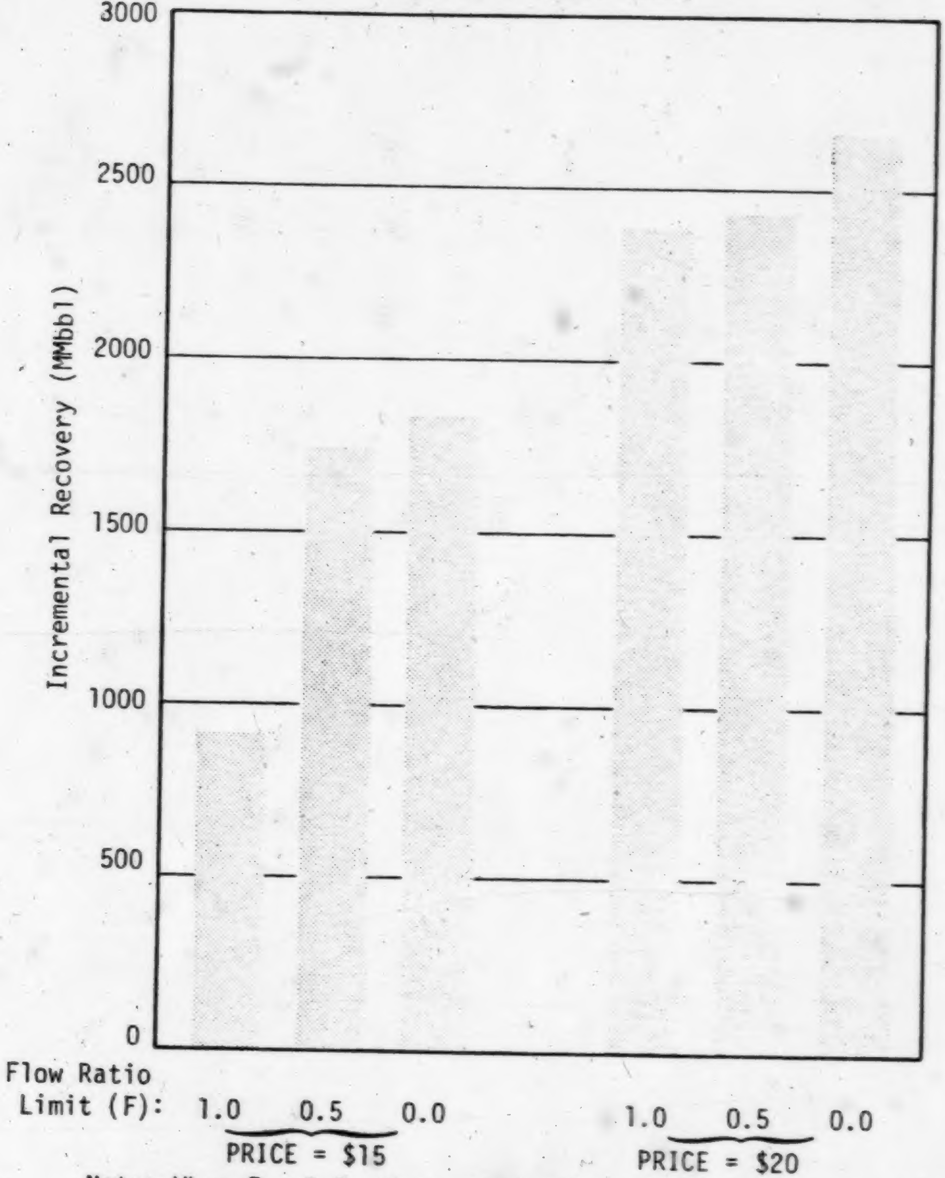
It might be reasonable to simply relax the constraint on flow rates instead of eliminating the check completely. This could be justified by the approximate nature of the data involved in calculating the theoretical limit. If we allow the rate implied by our models to be twice as large as the theoretical maximum, the ratio of theoretical to actual rates then must be less than or equal to 0.5. We increase recovery by only 35 million barrels in the $20 base case. This is shown in Figure 5.24. However, in the $15 price case the impact of relaxing the constraint is much more significant. The additional profitable reservoirs almost double ultimate recovery from 921 million barrels to 1,772 million barrels, an increment of 851 million barrels. At this price, eliminating the constraint completely would add only another 82 million barrels.

This result indicates that there is a significant amount of oil that is 'marginal' at the $15 price. The cost impact of the flow check makes this oil uneconomic at that price. A real price of $20 per barrel is high enough so that the extra costs have little impact on ultimate recovery.

5.2.3 Results of Extending the Implementation Schedule

Our analysis is based on the assumption that all projects come on stream within a 10 year period. This arbitrary assumption is somewhat optimistic given the current state of the art and the lead times required for development and evaluation of pilot projects. To determine how optimistic, we carried out the analysis using a 20 year implementation period scheduled as follows:

FIGURE 5.24: The Impact of Changing the Limit of the Ratio of Theoretical and Actual Flow Rates (Base Case)



Note: When F = 0.5, the actual production rate is allowed to be twice the theoretical maximum before cost penalties (in the form of extra wells) are imposed. When F = 0.0, the flowcheck is bypassed entirely (no cost penalties are imposed).

Year	1-3	4-6	7-9	10-12	13-15	16-20
% of Projects Started	2	3	4	5	6	8

This would not be expected to affect ultimate recovery since any profitable project under the 10 year start up scenario would also be profitable under the 20 year version. However, it might be expected to change the economic results since discounting occurs over a much longer time period. The results are shown in Table 5.8.

As expected, net present value decreased somewhat in the aggregate and for each process (except the steam stimulation process which starts in year one in both cases). Supply prices and discounted cash flow rates of return increased in some cases and declined in others, depending on the specific impact of the new schedule on the time profile of costs and production. The significance of these results lies in their relatively small magnitude. The economics are not much affected by a doubled startup schedule.

The variable that is significantly altered, of course, is production rate. The results are shown in Figure 5.25. The maximum aggregate daily production now peaks at 590 thousand barrels per day, again in 1992. This is not inordinately smaller than the 656,000 barrels per day rate realized in the 10 year case, which also occurs in 1992. Thus the overall impact of allowing an extra 10 years in which to initiate projects is seen to be fairly minimal. For individual processes the effect is more pronounced.

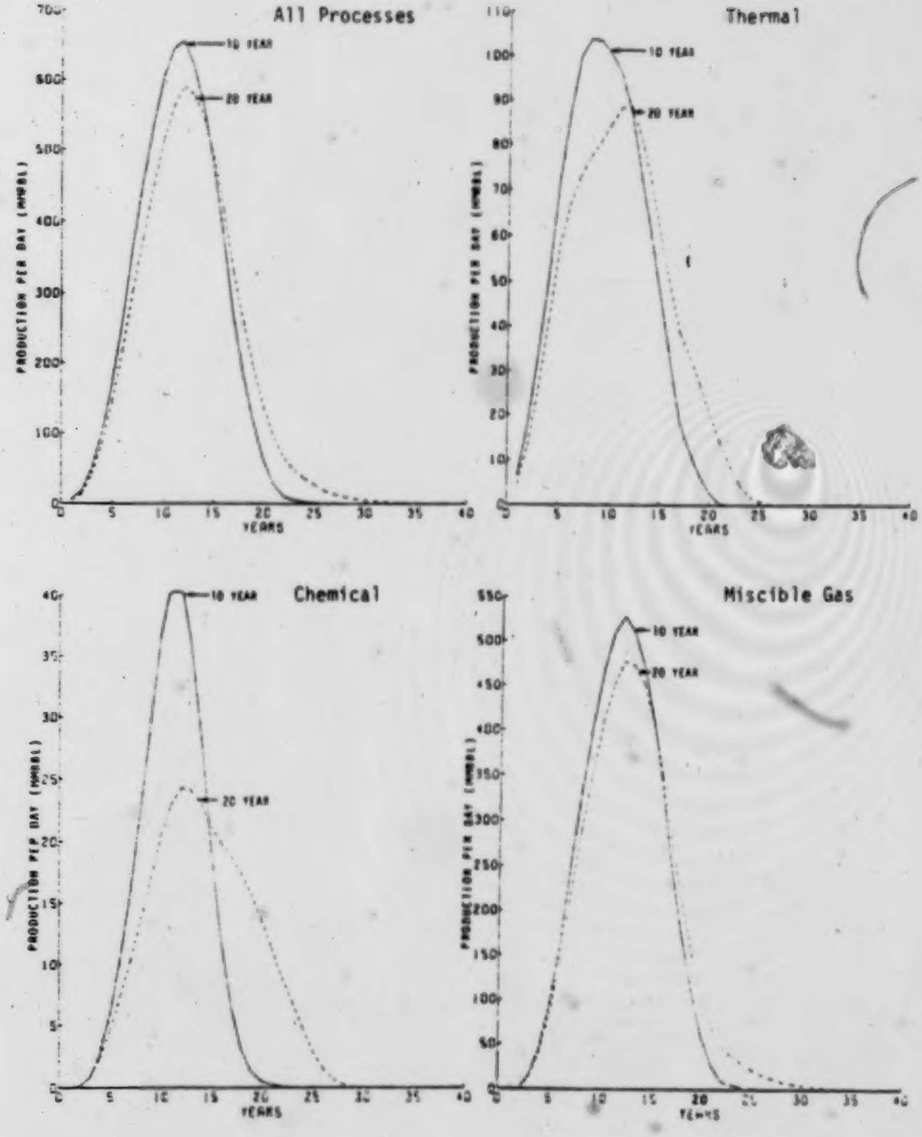
TABLE 5.8

COMPARISON OF RESULTS FOR 10 YEAR VERSUS 20 YEAR IMPLEMENTATION SCHEDULE

	Present Value of After Tax Net Revenue ($MM)		Supply Price ($)		Internal Rate of Return (%)		Forecast Incremental Recovery (MMbbl)
	10 yr	20 yr	10 yr	20 yr	10 yr	20 yr	
All processes	2,450	2,262	13.90	14.00	17	17	2,407
Thermal processes	756	726	10.50	10.20	131	118	407
Chemical processes	255	221	7.90	7.30	37	52	115
Miscible processes	1,439	1,314	15.20	15.40	13	13	1,885
Thermal							
Steam drive	254	252	7.20	7.20	75	74	90
Steam stimulation	327	327	10.20	10.20	176	176	101
In situ combustion	175	147	12.10	12.00	-	-	216
Chemical							
Polymer	23	18	12.70	12.90	30	29	15
Alkaline	229	202	6.60	6.10	41	53	93
Microemulsion	2	1	17.70	17.60	10	10	7
Miscible Gas							
Hydrocarbon miscible	1,124	1,039	15.30	15.40	14	14	1,352
CO_2 miscible	315	275	15.00	15.20	12	11	533

The thermal and miscible production rates are affected only moderately, with peak production being reduced by about 10 percent in each case. In the chemical process, however, peak production is reduced by almost 40 percent. This is discussed further in Section 6.2.

FIGURE 5.25: Daily Production Rates
(10 year versus 20 year start-up period)



Footnotes

[1] The exclusion of their estimate of additions to production due to infill drilling is justified on the basis that our extensive estimates of development activity necessary for tertiary recovery would likely substitute for infill drilling, not supplement it.

[2] The West Pembina play emerged in 1978 but information on new areas is held by the Board for a period of one to two years. Current estimates put its potential up to 0.5 billion barrels.

[3] Canada, National Energy Board, Canadian Oil Supply and Requirements (Ottawa: National Energy Board, September 1978), Appendix L. Requirements are sales adjusted by net imports, losses and other items.

[4] Actually one alkaline project came in at $233.06 but it represented only 65,000 incremental barrels and since the next highest supply price in alkaline was $44.79 we ignored it.

[5] Risk is also allowed for in other ways as discussed in Section 4.6.3.

[6] The actual rate of return in the no-tax case is 28.95 percent and in this tax case is 28.71 percent.

[7] In order to calculate the supply price with taxes and royalties included as a cost we aggregated all projects as if they started in the same year instead of utilizing our 'staggered' aggregation. This prevented any inconsistencies due to application of the tax procedures. The resulting supply prices are, however, slightly lower than those calculated from a staggered aggregation since they are discounted over a shorter time period.

[8] Note that one cannot multiply the rent per barrel calculated in this fashion by the number of barrels recovered to arrive at the economic rent reported in Table 5.6 because the units of measurement here are discounted barrels sometimes referred to as present barrel equivalents.

CHAPTER 6

SENSITIVITY ANALYSIS, INDIVIDUAL PROCESS RESULTS, AND CONSTRAINTS

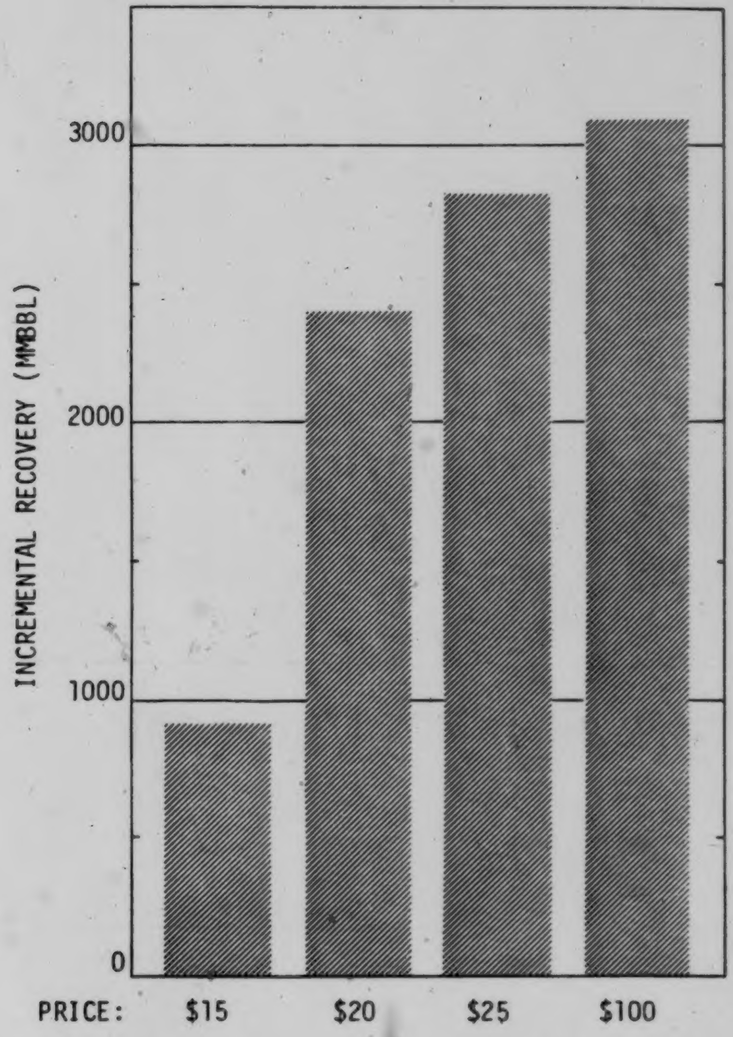
6.1 Sensitivity Analysis

The sensitivity of the results were investigated with regard to four critical parameters in the models: oil price, recovery factor, costs, and pattern size. The first two of these affect revenues, the last two affect costs (with pattern size having a particular impact on capital costs). Ultimately, they all affect net present value (revenues minus costs) and the pattern of their impact is similar. For that reason we present in the text the detailed results of the price variation only. Detailed results from varying the other parameters are presented in Appendix E.

6.1.1 Sensitivity of Incremental Recovery, Production Rates, and Process Shares to Changes in Oil Price Assumption

The base case assumptions of the previous chapter were a $20 per barrel oil price (in 1978 dollars), an 8 percent real discount rate, current estimates of costs, and current tax and royalty regulations. This section reports the results of incorporating two other oil price assumptions, namely $15 per barrel and $25 per barrel, also in 1978 dollars. In addition, selected results of a $100 per barrel price assumption are presented as an upper bound price case. Figure 6.1 illustrates the range of incremental recovery attributable to differing price assumptions. A $5 reduction in price reduces the expected recovery by almost 1.5 billion barrels (62 percent). A similar increase in the price increases potential by only 0.45 billion barrels

Figure 6.1: The Impact of Oil Price Increases on Tertiary Recovery.



(19 percent). The assymetry of these results reflects the fact that between \$15 and \$20 per barrel there are a number of marginal reservoirs.[1] As the price moves up to \$20 these marginal reservoirs come on stream. Thereafter there is much less scope for price increases to affect recovery given current technology. Even a price of \$100 per barrel would increase recovery only to a maximum of 3.1 billion barrels, a 29 percent increase on the base case. It should be noted, however, that a price increase of that magnitude would undoubtedly accelerate both laboratory and field research with resulting improvements in technology that would quite probably allow industry to break through the current technological limit.

The impact of price changes on individual process groups shows considerable variation. The incremental recovery associated with alternate prices is presented in Table 6.1 along with the variation from the base case estimate, in percentage terms. A useful summary statistic, elasticity of supply, is available to characterize these results. Defined as the percentage change in quantity supplied divided by the percentage change in price that caused it, the elasticity measure provides a dimensionless indicator of the responsiveness of quantity supplied to changes in price. Thus it is useful in comparing relative responsiveness to price changes for different commodities.

TABLE 6.1

VARIATION IN INCREMENTAL RECOVERY WITH PRICES

Price	Thermal		Chemical		Miscible	
	IR (MMbbl)	% Change in IR	IR (MMbbl)	% Change in IR	IR (MMbbl)	% Change in IR
15	280	-31	95	-17	547	-71
20	407	--	115	--	1,885	--
25	473	16	226	97	2,161	15

Table 6.1 provides the information required to calculate supply elasticities for the prices at which our estimates were made. The results are presented in Table 6.2.[2]

TABLE 6.2

SUPPLY ELASTICITIES FOR ENHANCED OIL RECOVERY

	Supply Elasticity (Response of Quantity Supplied to Changes in Price)			
Price Change	Thermal	Chemical	Miscible	All Processes
15-20	1.3	0.7	3.8	3.1
20-25	0.7	2.9	0.6	0.8
15-25	1.0	1.6	2.4	2.0

NOTE: Percentage changes in prices (quantities) are calculated from the average of the initial and final price (quantity). Thus the elasticity (E) is calculated as

$$E = (Q_2 - Q_1 \div (Q_2 + Q_1)/2) \div (P_2 - P_1 \div (P_2 + P_1)/2)$$
$$= \% \text{ change in } Q \div \% \text{ change in } P$$

Results are rounded to the nearest decimal.

The elasticities in Table 6.2 are interpreted as follows. An elasticity less than 1 indicates that the proportional increase in quantity is less than the proportional increase in price that caused it. Supply is said to be inelastic, implying relatively small response to price changes. An elasticity greater than 1 means supply is elastic over the price range used, implying a relatively large response to price changes. If the proportional change in quantity supplied is equal to the proportional change in price that caused it, supply is said to exhibit unitary elasticity.

In Table 6.2 we see that the chemical processes are inelastic over the price range \$15 to \$20, but respond quite strongly to the second \$5 increase in price, from \$20 to \$25. The thermal and miscible gas processes show an opposite response, both being elastic over the first \$5 price increase and inelastic over the second. Over the full \$10 price range investigated in the study, thermal processes exhibit unitary elasticity, and both chemical and miscible processes are elastic with the latter showing a somewhat stronger response.

Production rates associated with alternate prices are illustrated in Figure 6.2. These figures show roughly the same pattern. The difference between the impact on chemical and on miscible processes is clearly depicted. The chemical processes show a much greater response to price increases and a much smaller response to price decreases than the miscible processes. It appears that a few of the very highly productive chemical projects come on stream at prices of \$15 per barrel and significant increases in real prices are required to bring on the less productive reservoirs.

Table 6.3 shows the relationship between prices and the percentage share of total recovery that would be realized by each process.

FIGURE 6.2: Sensitivity of Tertiary Production to Oil Price Variations

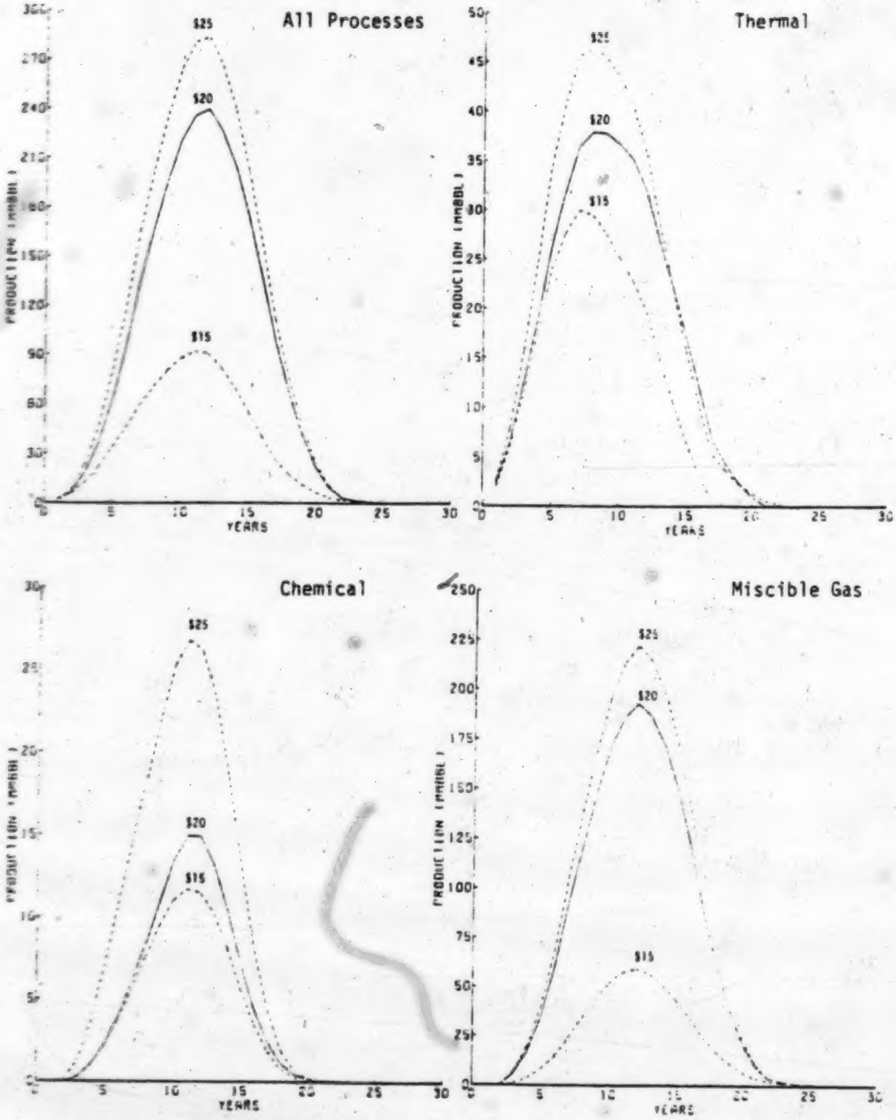


TABLE 6.3

PERCENTAGE SHARE BY PROCESS OF TOTAL TERTIARY PRODUCTION AT ALTERNATE PRICES

Price	Total Tertiary Recovery (MMbbl)	Thermal Share (%)	Chemical Share (%)	Miscible Share (%)
15	921	30	10	60
20	2,407	17	5	78
25	2,860	16	8	76
100	3,101	15	8	77

Shares are altered significantly by the move from $15 to $20 per barrel but further price increases have little effect. The thermal share declines because the bulk of the technically recoverable oil is profitable at $15 and there is so little scope for absolute increases in recovery at higher prices that the percentage share of this process is bound to fall. On the other hand, the fact that the chemical processes are able to maintain their percentage share indicates they enjoy significant increases in the absolute amount of oil recovered.

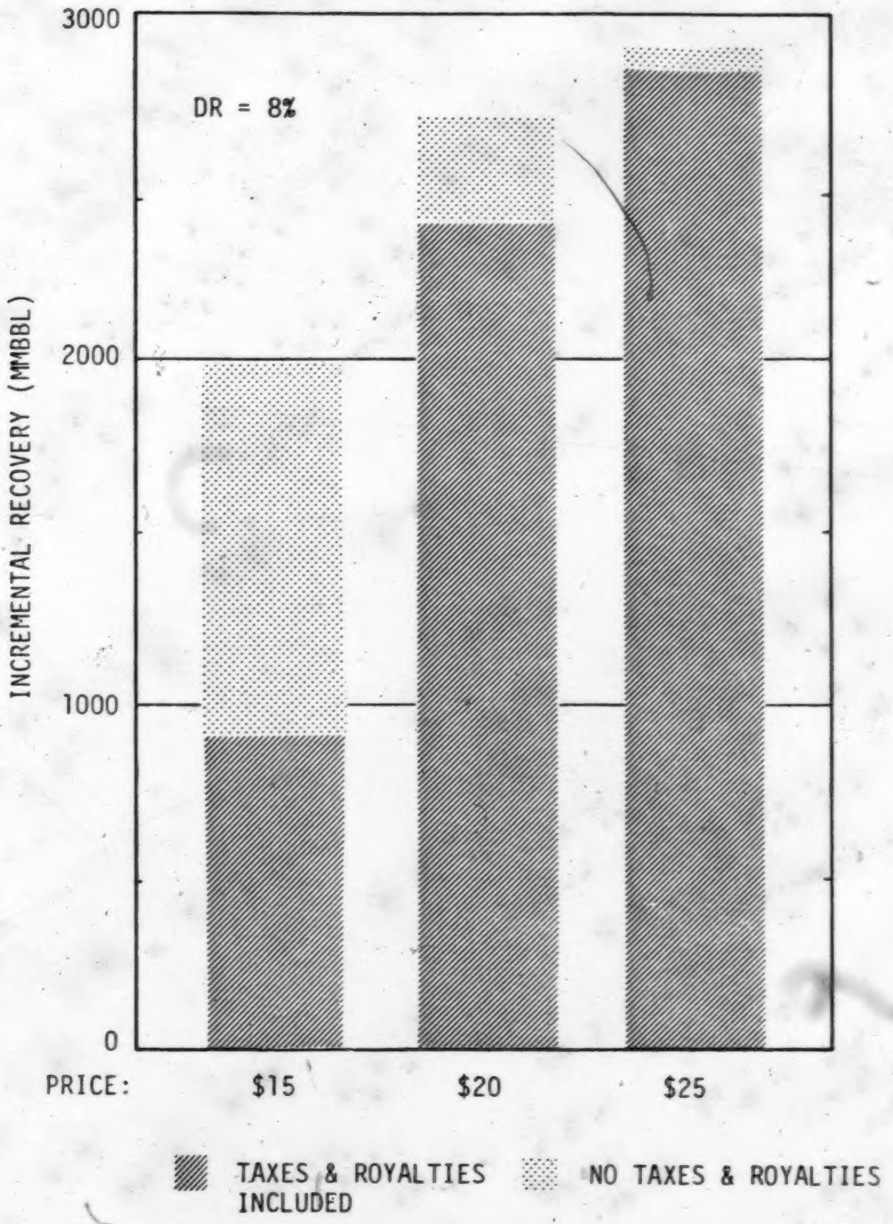
The implication of the response of recovery, production rates, and shares by process to price increases may be summarized as follows. Increases of wellhead prices will initially stimulate development of the more productive of the large heavy oil reservoirs subject to thermal recovery methods. A parallel but quantitatively more dramatic response should be seen in miscible-amenable reservoirs. Significant development of reservoirs amenable to chemical methods will be slower and more selective with most of the contribution awaiting wellhead prices almost double those in place in late 1979. A more precise illustration of the potential response of production to price changes is provided in a subsequent section on individual process results.

The results for all processes taken together tend toward those of the miscible processes since these represent such a large proportion of the total. The supply elasticity for all processes over the $10 price range is 2.0, which is an interesting number being approximately twice the elasticity of conventional oil supply according to some widely accepted estimates.[3] These numbers are intended for rather general purposes of comparison. The elasticity measure is ideally suited to the characterization of the responsiveness of quantity to very small changes in price as opposed to the large price changes of this study. Also, the noted estimates that established an elasticity of one for conventional oil and gas supply were based on much lower initial prices than used here and would not necessarily apply now. With these caveats in mind, however, the numbers do provide some basis for comparative perspective.

6.1.2 Social Value and Prices

In Section 5.2.1 the point is made that a reasonably efficient tax and royalty system would have little impact on real economic activity, in the present context the production of tertiary oil. The direct impact of the tax system on incremental recovery is revealed by Figure 6.3. At a price of $20 to $25 the reduction in production due to tax-royalty impacts on profitability is significant but not striking. At the $15 price level the tax impact reduces production by one billion barrels, a seemingly staggering amount. However, the eliminated reservoirs are relatively high cost projects so that the reduction in net social value is actually modest--less than that attributable to the 300 million barrel reduction due to taxes in the base case. This is illustrated in Table 6.4 where the estimate of the

Figure 6.3: The Impact of Oil Price Increases on Tertiary Recovery with and without Tax and Royalty Effects.



social value of tertiary activity for the base case in Section 5.2.1 is combined with similar considerations for price cases of $15 and $25 per barrel. Potential net social value is based on the profitable reservoirs without tax considerations while realized social value is based on the profitable reservoirs under current tax and royalty regulations. The difference measures the real cost of the tax system.

TABLE 6.4

POTENTIAL AND REALIZED SOCIAL VALUE UNDER
DIFFERING PRICE ASSUMPTIONS
(discount rate = 8%)

Price	Potential Net Social Value ($billion)	Realized Net Social Value ($billion)	Change in Net Social Value Attributable to the Impact of the Tax System ($billion)
15	3.3	3.0	0.3
20	7.4	7.0	0.4
25	12.4	12.3	0.1

The tax system is unsuccessful in avoiding interference with production at all prices but its most adverse impact occurs at the $15 price of oil where it would reduce net potential social value by $300 million. This represents 9 percent of the potential whereas the larger $400 million reduction in the $20 price case is only 5.4 percent of the potential value.

6.1.3 Revenue Shares and Prices

Table 6.5 shows the overall division of revenues discounted at a real rate of return of 8 percent for each price level. Positive net revenues are by definition economic rent--a return over and above what is theoretically required to keep or attract the resources to this activity. The table sets out the division of the rent between industry and government for various price levels.

TABLE 6.5

DIVISION OF NET REVENUE BETWEEN INDUSTRY
AND GOVERNMENT AT ALTERNATE PRICES
(discount rate = 8%)

Price	Total Net Revenue	After Tax Net Revenue	% of Total	Tax Take	% of Total
15	2,989	1,173	39	1,816	61
20	7,005	2,450	35	4,555	65
25	12,327	4,565	37	7,762	63
100	93,331	37,771	41	55,560	59

The results show little variation with price. Company surplus profits are in a range of 35-40 percent of the total benefit from tertiary recovery more or less regardless of the absolute levels of profitability due to a variation in crude oil prices alone.[4] Once again we see that the current tax and royalty regime is not finely tuned as a progressive schedule on surplus profit or rent.

6.1.4 General Impact of Price Variations on Economic Results

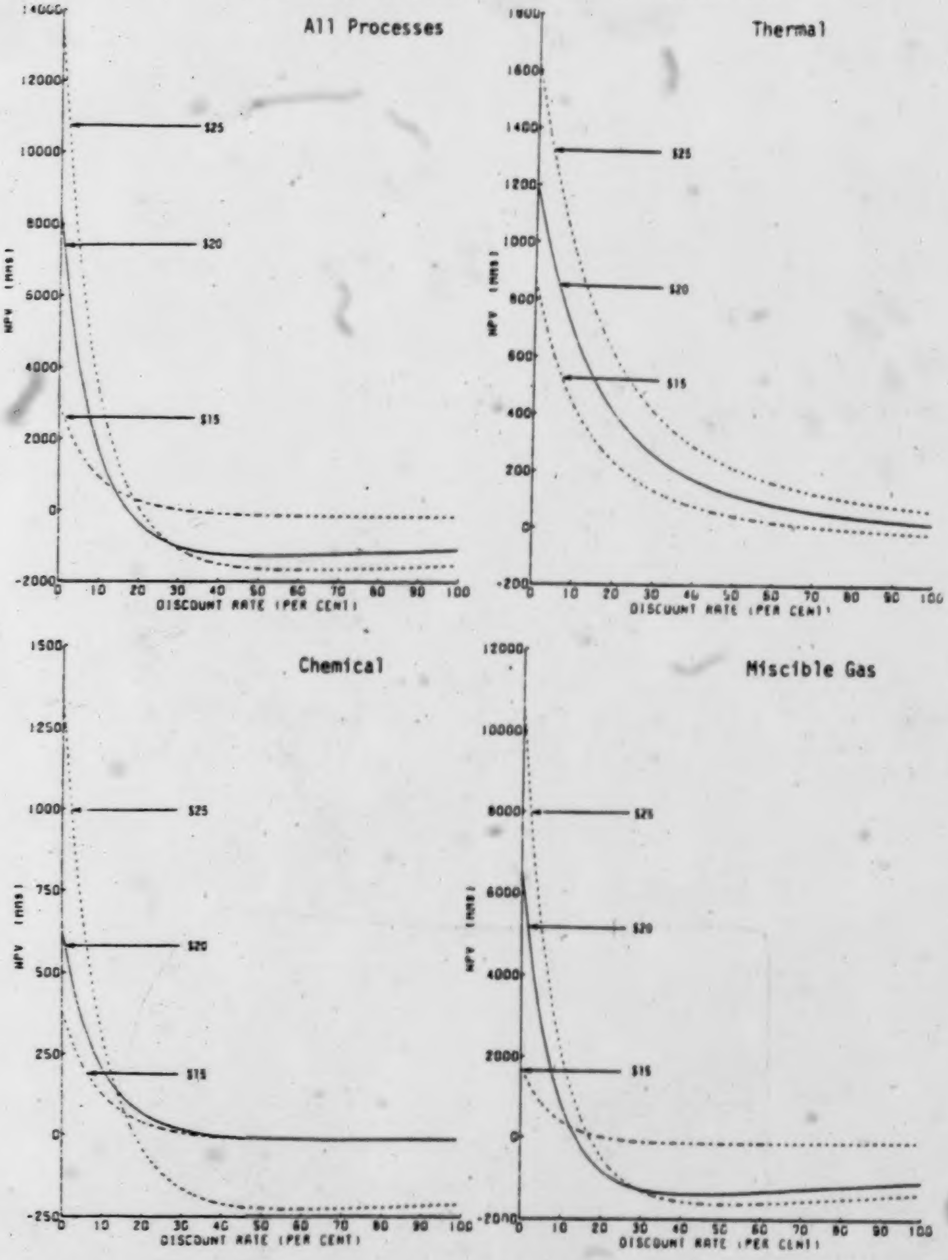
The impact of varying price levels on economic parameters is set out in Table 6.6. Revenue, taxes, and incremental recovery all increase with increased prices as would be expected. This result holds, however, only for a range of discount rates from 0 to 15 percent. Outside this range the result depends on the timing of the additions to revenues and costs. This is illustrated by Figure 6.4.

TABLE 6.6

ECONOMIC RESULTS OF PRICE SENSITIVITY ANALYSIS

	Realized Present Value				
	Net Revenue ($MM)	Taxes & Royalties ($MM)	Supply Price ($)	Internal Rate of Return (%)	Forecast Incremental Recovery (MMbbl)
All processes					
15	1,173	1,816	8.60	31	921
20	2,450	4,555	13.90	17	2,407
25	4,565	7,762	16.10	20	2,860
100	37,771	55,560	38.10	56	3,101
Thermal					
15	489	738	7.80	76	280
20	756	1,435	10.50	131	407
25	1,065	2,238	13.00	232	473
100	5,745	12,095	38.40	--	480
Chemical					
15	156	261	6.10	34	95
20	255	422	7.90	37	115
25	426	700	15.10	18	226
100	3,919	4,687	27.60	53	236
Miscible					
15	528	817	9.60	20	547
20	1,439	2,698	15.20	13	1,885
25	3,073	4,824	17.10	17	2,161
100	28,106	38,779	39.10	42	2,385

FIGURE 6.4: Variation of Realized After Tax Net Present Value (at alternate oil prices) with Assumed Discount Rates

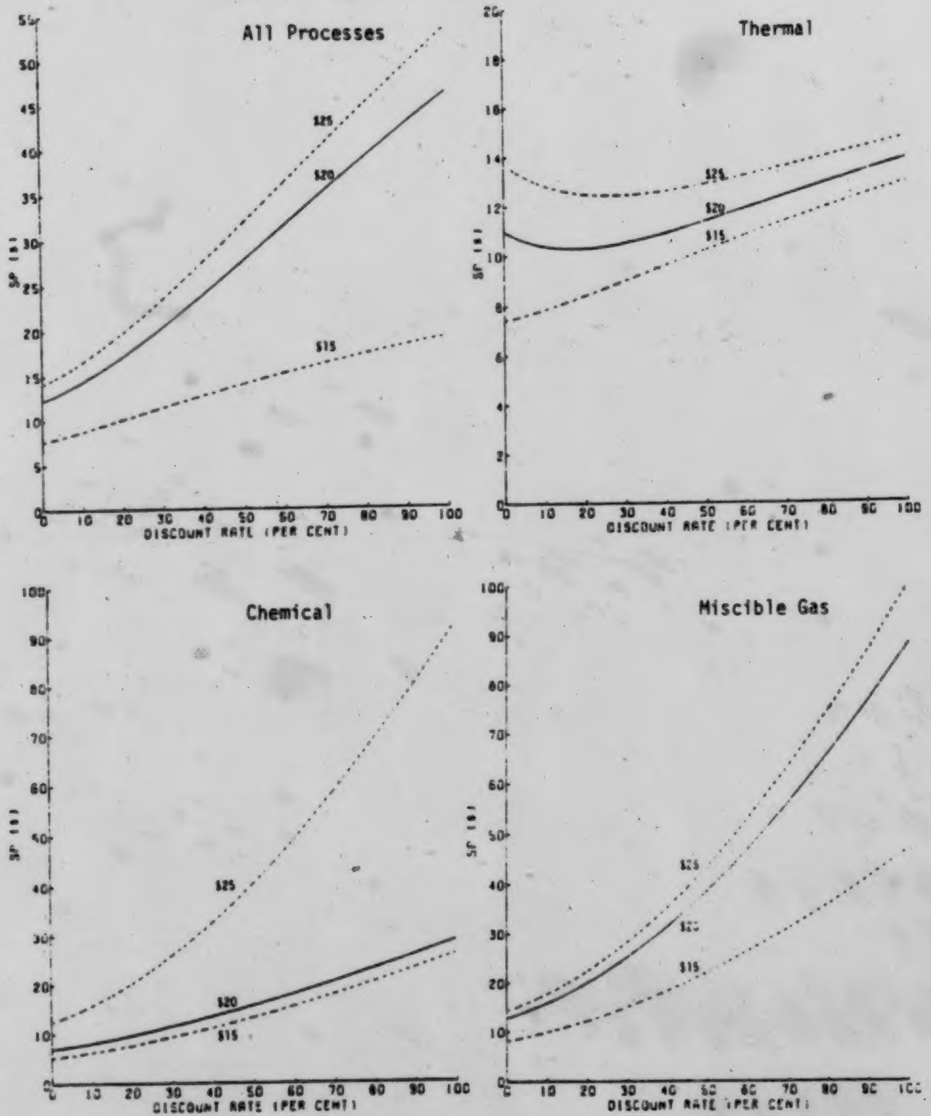


These figures show how industry's economic profit declines as the assumed rate of discount (required rate of return) increases. The result is presented for all three assumed oil price levels. The shape of the curves differs for different prices since each price involves a different set of viable projects with differing streams of net profit over time. This leads to an interesting result which can be illustrated with the help of Figure 6.4, All Processes. There the economic profit curves for the \$15 and \$20 cases intersect at a discount rate of about 13 percent. This means that at a 13 percent discount rate the net present value of the projects profitable at a \$15 oil price is the same as the net present value of the projects profitable at a \$20 oil price. And this is the case in spite of the fact that the undiscounted value of the \$15 projects is less than one half that of the \$20 projects. The latter price generates a larger set of projects but the additional reservoirs have associated higher costs of development, the timing of which causes net present value to decline at a higher rate with increasing rates of discount. The thermal processes do not exhibit this tendency because they involve the same set of projects (and therefore costs) in all price cases since they are profitable even at the lowest price assumed here.

Supply prices vary directly with oil prices and with assumed discount rates across the entire range of discount rates as shown in Figure 6.5. This is an expected result since higher prices allow higher cost reservoirs to come on stream, increasing the amount required to recover all costs per barrel.

The internal rate of return varies unpredictably since both costs and revenues increase with higher prices. The emerging rate that equates the present value of these two is dependent on the timing as

FIGURE 6.5: Variation of Supply Price Calculation (at alternate oil prices) with Assumed Discount Rate



well as the magnitude of the additions and no systematic variation would be expected.

6.2 Individual Process Results

Two kinds of analysis were applied to the results of individual reservoir evaluations. First we considered each process on its own, that is, technically acceptable reservoirs were simply checked for profitability (NPV greater than 0). A reservoir could, therefore, qualify under two or more processes. This procedure indicates the maximum potential for each process.

Next we allocated each reservoir to its economically dominant process, that process which provides the highest net present value. In the first procedure, since many reservoirs were amenable to more than one process, we had a total of 1,536 projects under consideration. After trimming this number down to economically dominant pools we were left with 643 reservoirs, 460 of which are profitable at a price of $20 if regular taxes and royalties are charged against them.

The former procedure provides useful perspective for our analysis of the profitable potential for each process. For example, polymer augmented waterflooding could be profitable in 197 reservoirs but in 145 of these some other process dominates. If for some reason these other processes are found unworkable we would still have the profitable option of polymer available. The latter procedure results in our forecast of what is likely to be the amount of tertiary recovery by various processes given current technology and costs.

In the earlier chapters our analysis concentrated on the economically dominant reservoirs in each process only. This section provides a brief comparison of the forecast potential of each process and the maximum potential by process. The forecast potential emerges after economic dominance by process is established. The maximum potential of each process emerges from considering only technical and economic feasibility. Both forecast and maximum potential would, of course, increase at higher prices of oil. However, all results discussed in Section 6.2 relate to the base case with its assumed oil price of $20 per barrel and discount rate of 8 percent.

6.2.1 Chemical Processes

Incremental recovery

Microemulsion, polymer, and alkaline floods dominate in 151 reservoirs and are profitable in 110 of these under our $20 price and 8 percent discount rate assumptions. Polymer accounts for 15 million barrels, alkaline for 93 million barrels, and microemulsion for 6 million barrels in our base case.[5] The total of approximately 114 million barrels represents about 5 percent of total potential.

Alkaline flooding dominates in 82 reservoirs but could be applied to 119, 92 of which would be profitable at a $20 price. Maximum recovery would be 113 million barrels, an increase of 19 million barrels over what the alkaline economically dominant reservoirs alone would produce.

The polymer process is a possibility in 197 reservoirs of which 118 would be profitable at the $20 price, increasing polymer recovery from 15 million barrels (in our base case) to 42 million barrels.

Although microemulsion flood is largely dominated by other processes, it is a technical possibility in 148 reservoirs, 25 of which would be profitable at the $20 price. Maximum incremental recovery would increase from 6 to 74 million barrels.

Competitive and full potential is illustrated for each process in Figure 6.6. This figure shows clearly the significant potential of the microemulsion process which is, however, seriously dominated by other processes in an economic sense. Successful reduction of costs of the surfactant could increase the economic potential of this process significantly since it is technically superior in its ability to displace oil.

Production rates

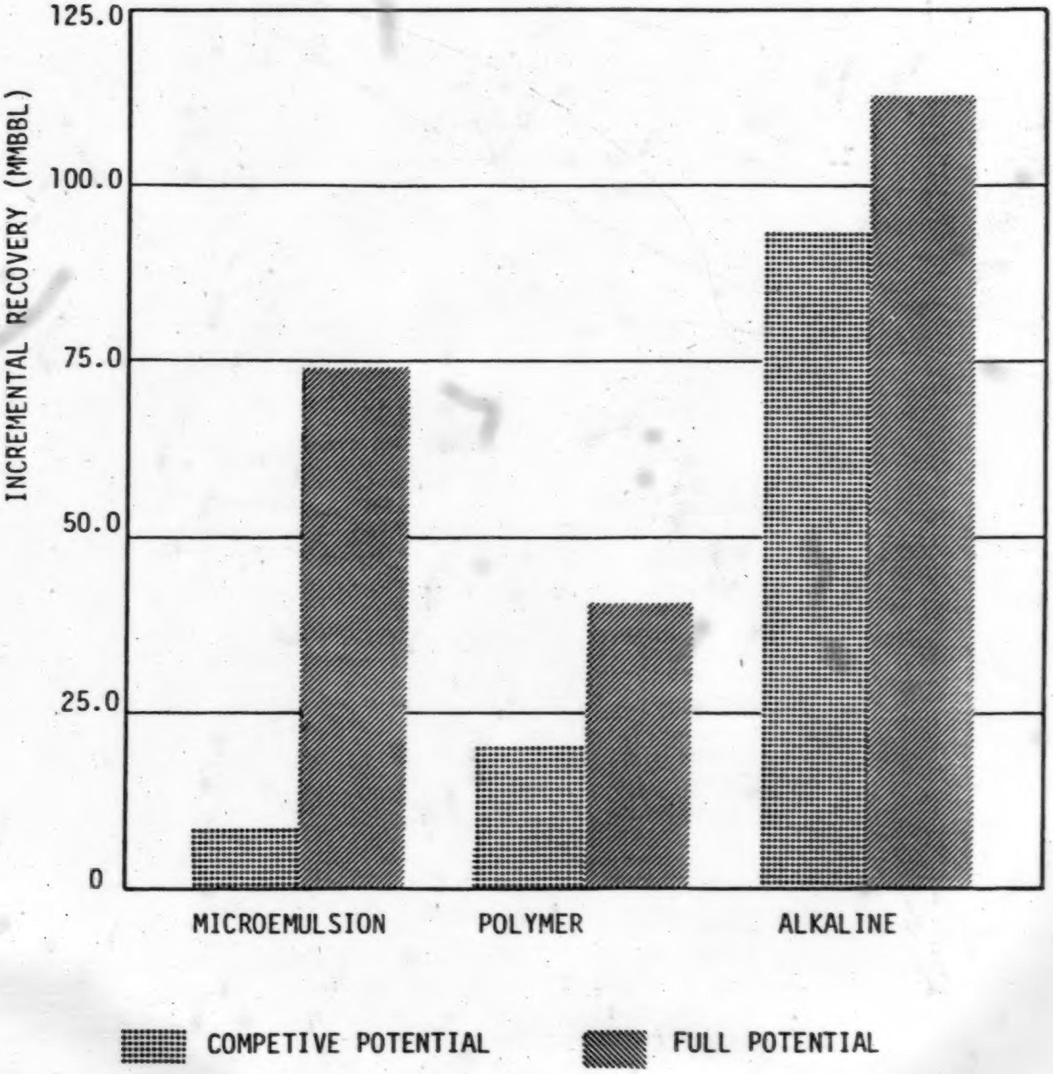
Daily production rates for the chemical processes are shown in Figure 6.7. The solid lines show the rates that would emerge from a 10 year implementation schedule while the dashed lines show the rates if a 20 year implementation schedule is followed. The following discussion assumes that the highest ranked projects would get underway by 1981.

For alkaline, in the 10 year case production begins in 1982, peaking in 1991 at 33 Mb/d (12 MMb/yr) and continuing at declining rates to the year 2000. The 20 year implementation schedule also has production beginning in 1982 but it peaks 10 years later at 21 Mb/d (8 MMb/yr) and continues an extra 9 years to 2009.

For polymer, the 10 year scenario has production over the 20 year period between 1983 and 2002. Production rates peak in 1992 at 5 Mb/d (2 MMb/yr). The 20 year scenario begins production in 1986, peaks in 1997 at 3 Mb/d (1 MMb/yr) and terminates in 2009.

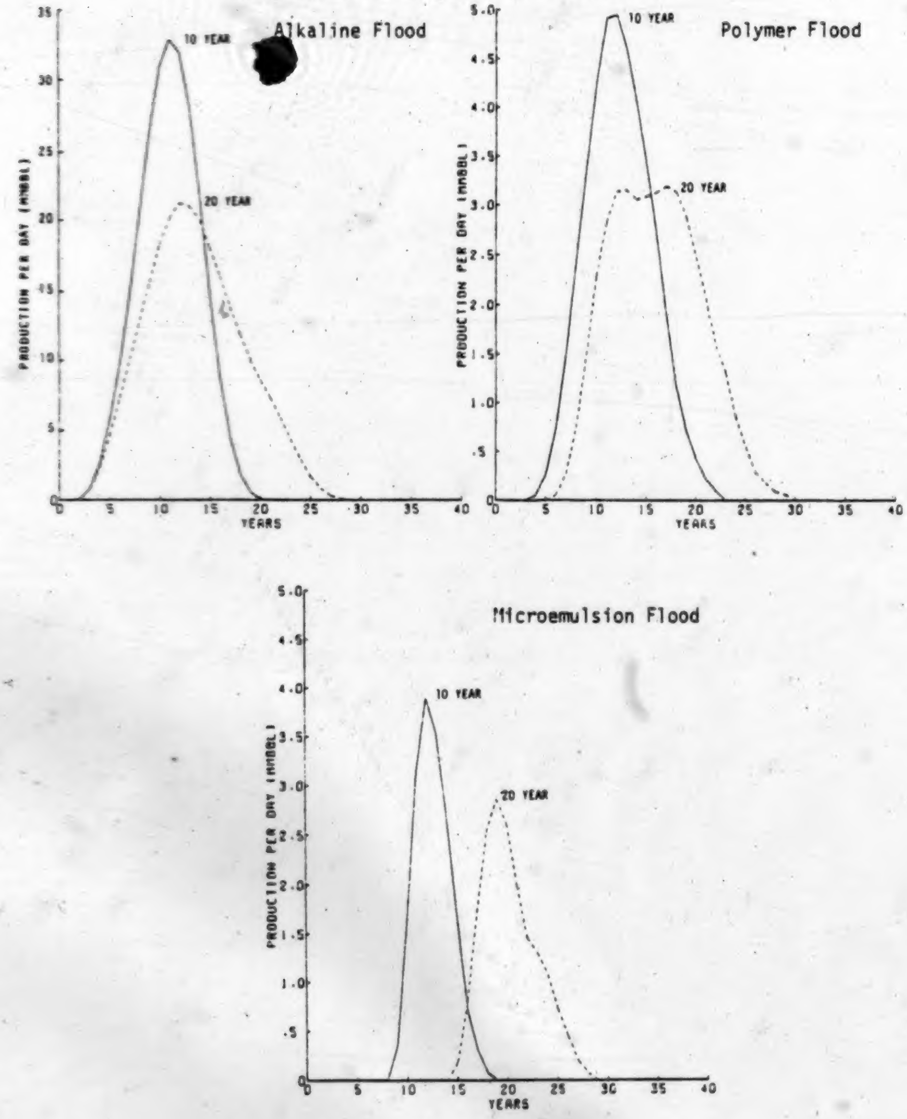
The microemulsion process is the most affected by extending the implementation schedule. With 10 year start up production begins in 1989, peaks in 1992 at 4 Mb/d and terminates in 1998. Twenty year start up delays the first production until 1995. Production then peaks in 1999 at 3 Mb/d and terminates in 2008.

FIGURE 6.6: Competitive Potential Versus Full Potential Chemical Processes



NOTE: Base case comparison of the 'competitive potential' of each process when it is limited by competition from other processes that dominate it economically with the 'full potential' of each assuming no competition from other processes.

FIGURE 6.7: Daily Production Rates
(10 year versus 20 year start-up period)



Costs of development and operation

A significant proportion of the costs of developing any of our projects depended on the reaction to the flow check. Failure to satisfy this constraint automatically led to a 20 percent increase in wells drilled, increasing capital, operating and overhead charges for every well affected in the base case (and all other cases except special ones designed specifically to investigate the impact of the flow check as reported in Section 5.2.2). The impact of the flow check on the chemical reservoirs is set out in Table 6.7.

TABLE 6.7

IMPACT OF FLOW CHECK BY PROCESS

	Economically Dominant No. of Reservoirs	Reservoirs With Increased Drilling Due to Flow Check			Percentage of Reservoirs Affected
		Production	Injection	Total	
Alkaline	82	2	20	20	24
Polymer	52	22	49	49	94
Microemulsion	17	0	13	13	76
Total	151	24	82	82	54

The table shows that both polymer and microemulsion processes were greatly affected by the production constraint and costs were increased significantly above what they would have been in its absence.

The cost breakdown by category and the flow of costs over the development period are presented in Figures 6.8 to 6.15 for individual processes and the chemical group as a whole. The figures showing the yearly cost flows combine operating costs and costs of materials and plot the sum as variable costs of production. In these diagrams fixed

FIGURE 6.8

UNDISCOUNTED COSTS BY CATEGORY
CHEMICAL PROCESSES (BASE CASE)

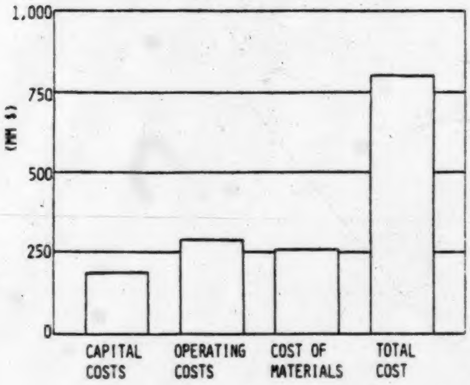


FIGURE 6.9

TOTAL COST BREAKDOWN, CHEMICAL PROCESSES
BASE CASE

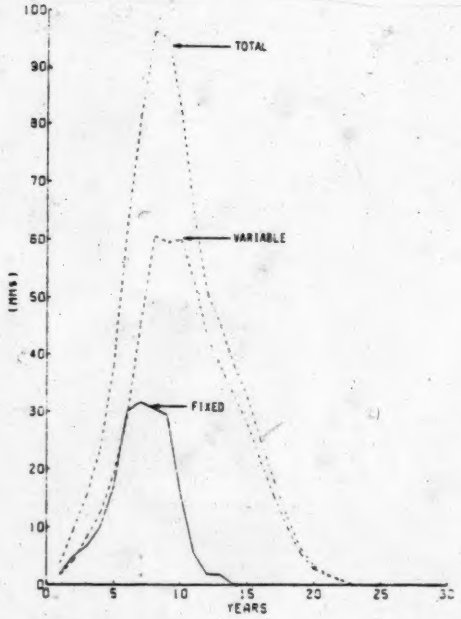


FIGURE 6.10

UNDISCOUNTED COSTS BY CATEGORY
ALKALINE FLOOD (BASE CASE)

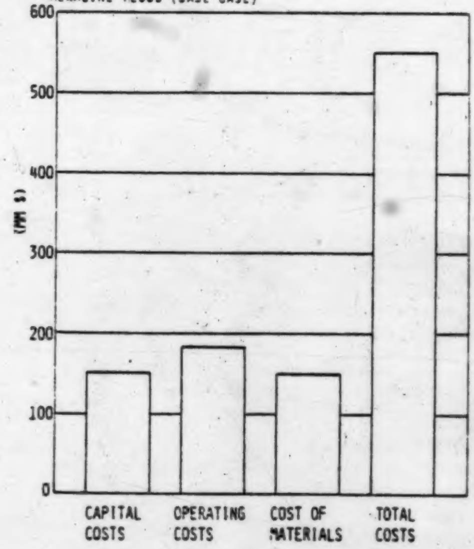


FIGURE 6.11

TOTAL COST BREAKDOWN, ALKALINE FLOOD
BASE CASE

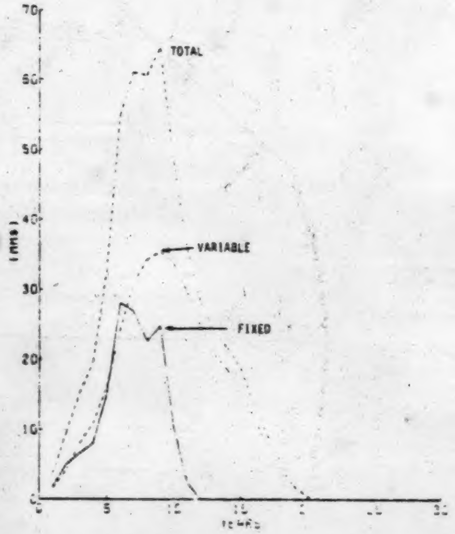


FIGURE 6.12

UNDISCOUNTED COSTS BY CATEGORY
POLYMER FLOOD (BASE CASE)

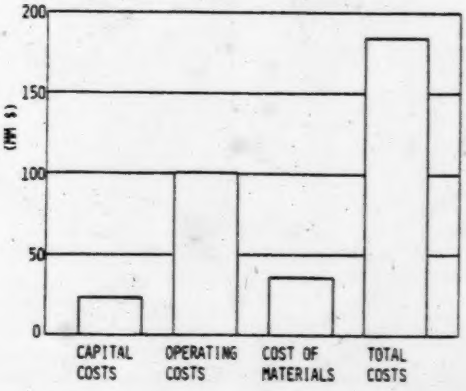


FIGURE 6.13

TOTAL COST BREAKDOWN, POLYMER FLOOD
BASE CASE

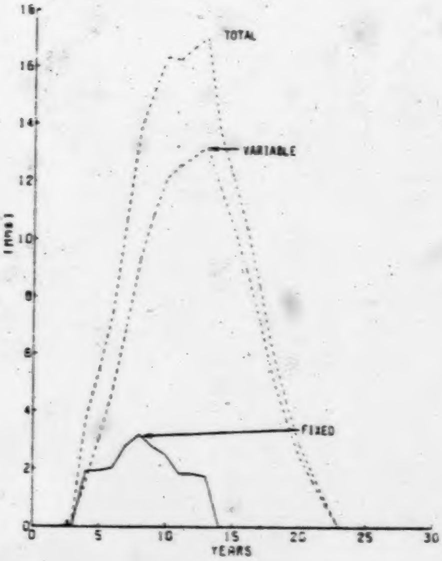


FIGURE 6.14

UNDISCOUNTED COSTS BY CATEGORY
MICROEMULSION FLOOD (BASE CASE)

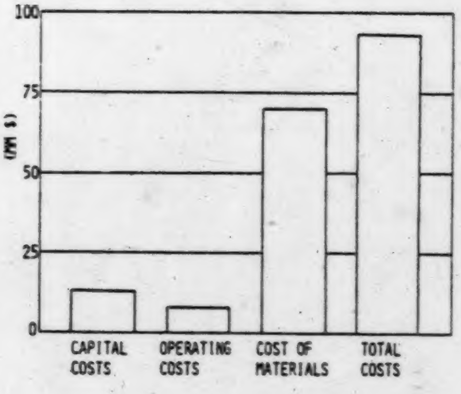
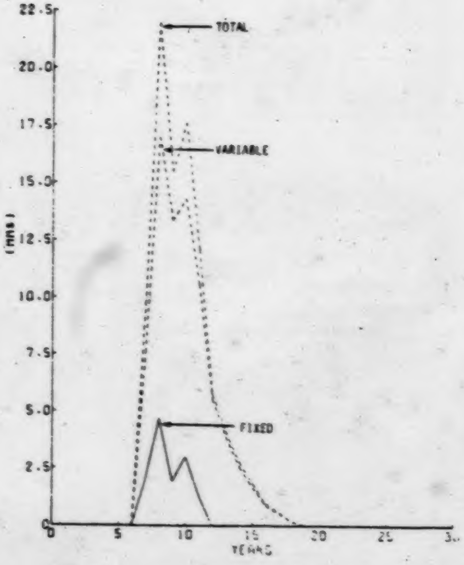


FIGURE 6.15

TOTAL COST BREAKDOWN, MICROEMULSION FLOOD
BASE CASE



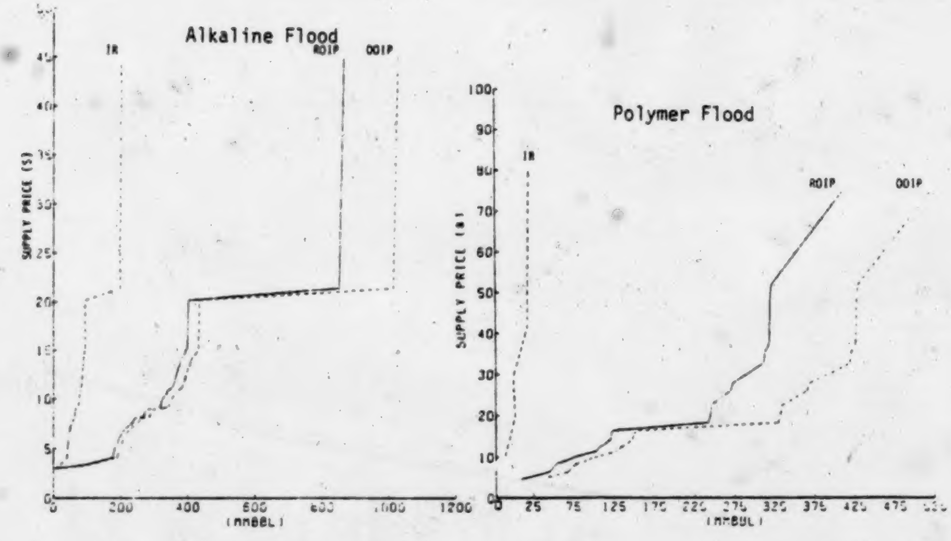
capital costs are seen to be relatively small compared to the variable production costs. As expected, materials cost is by far the most important in the microemulsion process. Successful reduction of surfactant costs through economies of large scale production could make this a very attractive process in future.

Costs per barrel over the development period

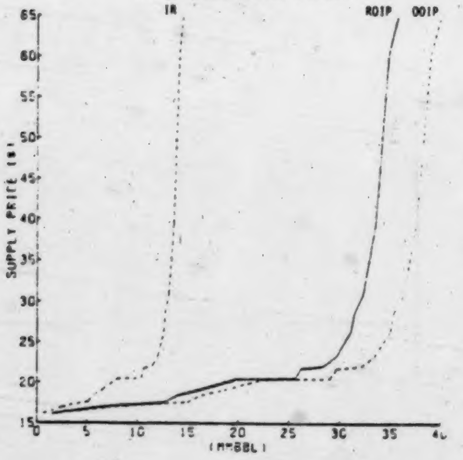
Section 4.6 establishes the theoretical basis of the supply price which is an amount per barrel that must be received over the life of each project if all real costs of production are to be recovered. Each reservoir will have a unique supply price which depends on the general quality of the reservoir. If we define a 'market price' as the average revenue per barrel that is actually received over the development period, then whenever the market price is greater than or equal to the supply price for a particular reservoir that reservoir will be profitable and will be brought on stream. For each reservoir that is brought on stream we have an estimate of original oil in place (OOIP), remaining oil in place (ROIP) after ultimate primary and secondary recovery operations are complete, and incremental recovery (IR) due to tertiary efforts. Figure 6.16 depicts the relation between the supply price and these three magnitudes.

Supply prices for the alkaline group ranged from \$3.02 to \$44.79, with the overall weighted average supply price for reservoirs profitable at a \$20 market price being \$6.64.[6] In the polymer groups the range was from \$4.08 to \$96.05 with an overall supply price of \$12.70 for profitable reservoirs. The microemulsion supply prices ranged from \$16.15 to \$64.87 but when only the profitable reservoirs were included the average was \$17.68. The relative high costs of the

FIGURE 6.16: Supply Price and Incremental Recovery
IR: Incremental Recovery
ROIP: Remaining Oil in Place
OOIP: Original Oil in Place



Microemulsion Flood



microemulsion process are again apparent.

If we calculate taxes and royalties for each project based on a particular price ($20) then we can incorporate this amount into the supply price calculation to get an overall average amount per barrel required for the company to realize its required return (8 percent real or 15 percent nominal in this case). Figure 6.17 presents the results of that exercise, the dashed line representing the supply price calculated with taxes and royalties considered as a cost. This line eventually merges with the initial line because when the 'real' supply price exceeds $20 per barrel, taxes are eliminated. The dashed line therefore is really relevant only to the particular price under which the tax calculation is made and it essentially shows the extra cost per barrel that the tax system imposes on the operator.

Social value and division of revenue

The value of production, its distribution and social and private rates of return for the chemical group is shown in Table 6.8. The company share rises to 46 percent in the polymer case but overall remains in the usual range (at 38 percent). Before and after tax rates of return indicate alkaline is the most profitable with polymer a close second and the high cost microemulsion group a poor third.

FIGURE 6.17: Required Cost per Barrel of Additions to Petroleum Reserves through Enhanced Oil Recovery

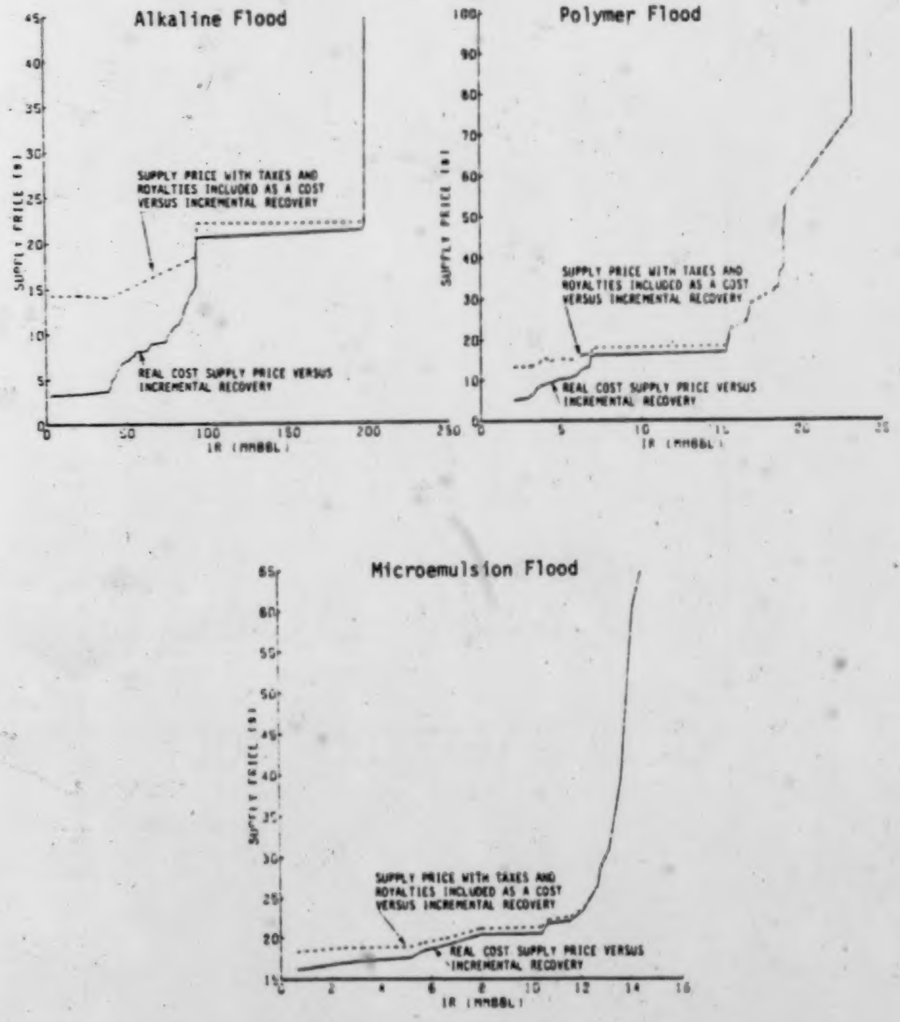


TABLE 6.8

REVENUE SHARES AND RATE OF RETURN AT AN OIL PRICE OF $20 AND ASSUMING AN 8 PERCENT DISCOUNT RATE CHEMICAL PROCESSES

	Realized Net Social Value ($MM)	Operator Net Present Value ($MM)	Tax Take ($MM)	Social Rate of Return (%)	Private Rate of Return (%)
Chemical	678	255	423	68	37
Alkaline	621	229	392	72	41
Polymer	50	23	27	48	30
Microemulsion	7	3	4	13	10

6.2.2 Miscible Processes

Incremental recovery and rates of production

Hydrocarbon and carbon dioxide miscible processes dominate in 446 reservoirs and are profitable in 309 of these. Carbon dioxide miscible accounts for 533.8 million barrels and hydrocarbon miscible for 1,352 million barrels, which combined represents about 78 percent of the total potential for tertiary recovery.

Carbon dioxide flooding is largely dominated by the hydrocarbon miscible process but it could be applied in 500 reservoirs, profitable (at $20) in 296 of these for a maximum incremental recovery of 830 million barrels, or 297 million barrels more than indicated in the base case forecast which includes only profitable reservoirs that have the highest net present value (are dominant).

Hydrocarbon miscible also could be applied in 500 reservoirs and would be profitable in 368 of them providing a maximum possible hydrocarbon recovery potential of 2,122 million barrels or 770 million more than is available from only the hydrocarbon dominant pools.

Competitive potential versus full potential is shown in Figure 6.18. For the most part these two processes are in competition with each other, particularly in the carbonate regions. If either of them proved unworkable the other would likely expand to meet its full potential. Production rates for the 10 and 20 year start up cases are shown in Figure 6.19.

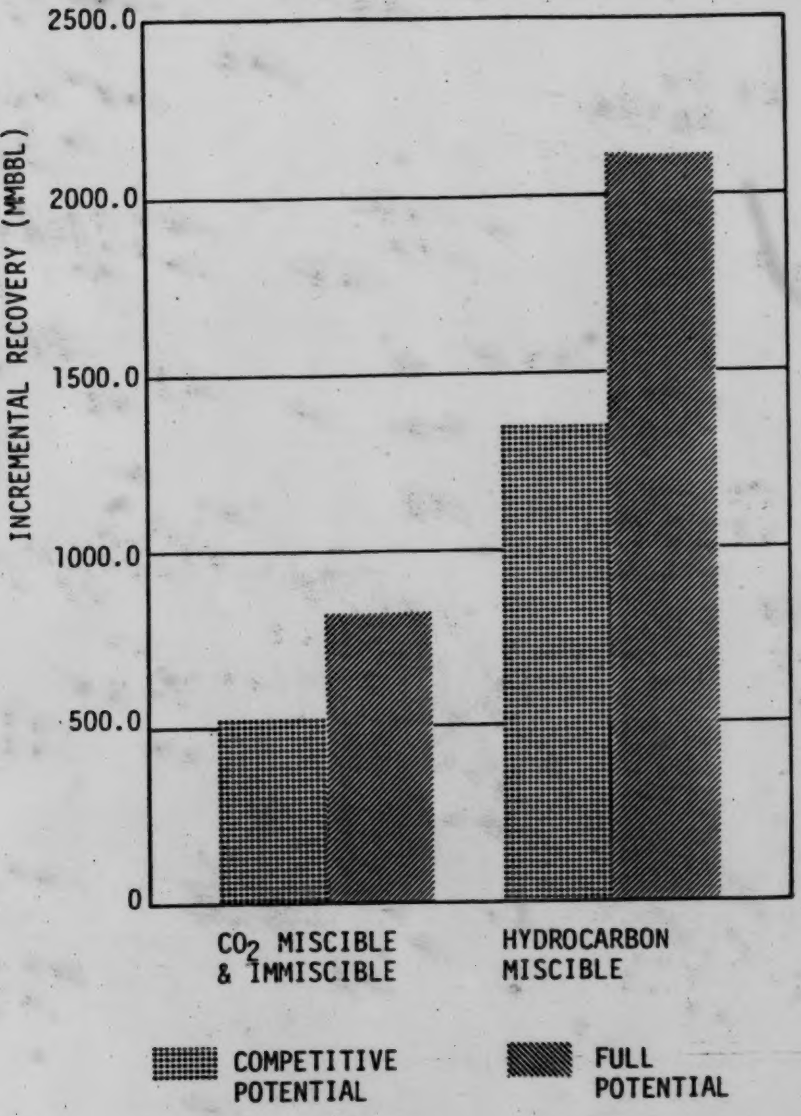
Relatively speaking, the longer implementation period has very little impact on the production profile. For carbon dioxide processes, in both cases production begins in 1993 but in the 20 year case it lasts 8 years longer, terminating in 2011. Peak production hits 150 Mb/d in 1992 in the 10 year start up case and 133 Mb/d in 1993 in the 20 year case. Similar results are found for the hydrocarbon miscible case. Both cases peak in 1992 but the 20 year case continues production until 2017, 9 years beyond the 10 year case. At the peak there is only 34 Mb/d difference in the two cases, 378 versus 344 Mb/d.

Carbonate versus sandstone reservoirs

About 47 percent of the original oil in place in Alberta was contained in carbonate reservoirs. These reservoirs are generally less permeable and this and other technical reasons make the miscible gas processes the most likely to be used. The carbonates then were checked for viability with the carbon dioxide and hydrocarbon miscible processes only. Table 6.9 sets out the split in potential for these processes between carbonates and sandstones. The percentage split within the miscible processes and including all process groups is shown in Figures 6.20 and 6.21.

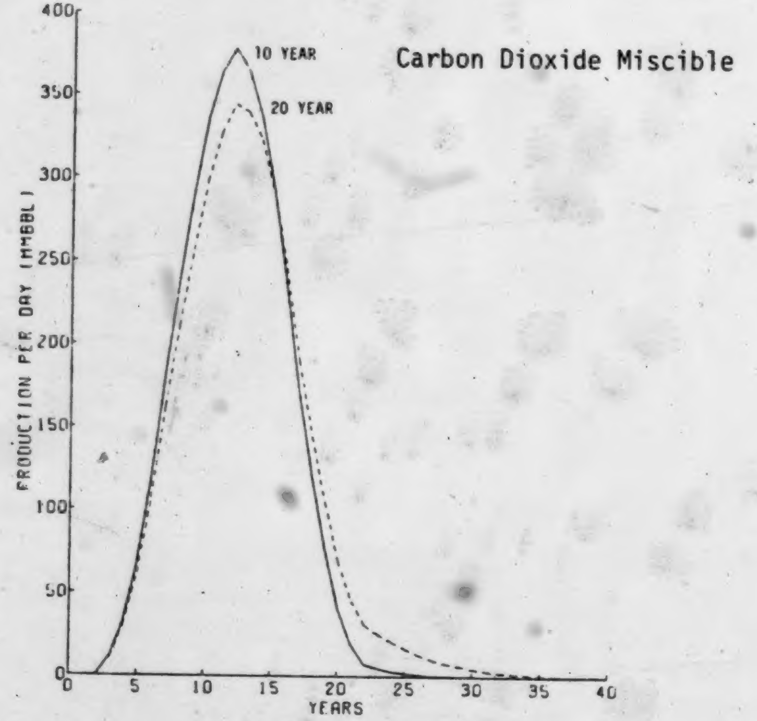
Although there are a larger number of reservoirs in the carbonate group the somewhat lower productivity due to lower oil in place and tighter formations reduces their ultimate potential below

FIGURE 6.18: Competitive Potential versus Full Potential (Miscible Gas Processes)

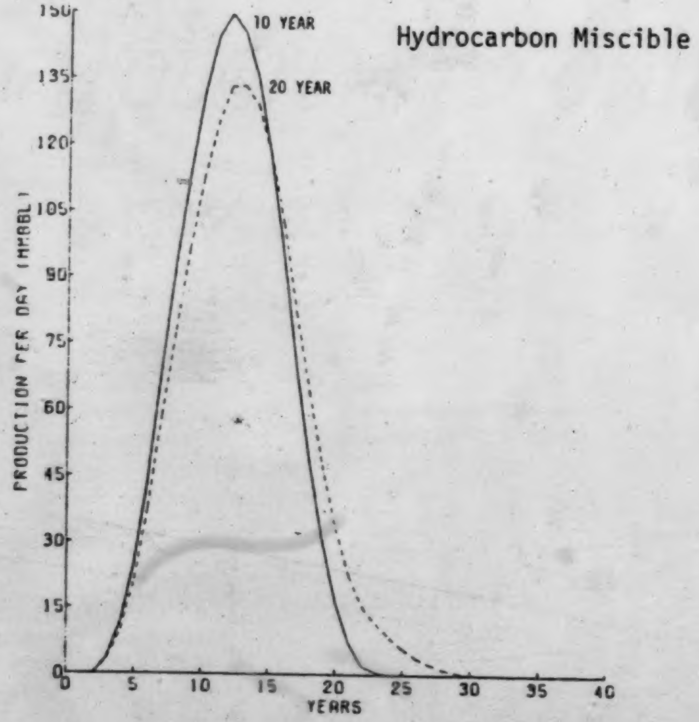


Note: Base case comparison of the 'competitive potential' of each process when it is limited by competition from other processes that dominate it economically with the 'full potential' of each assuming no competition from other processes.

FIGURE 6.19: Daily Production Rates
(10 year versus 20 year start-up period)



Carbon Dioxide Miscible



Hydrocarbon Miscible

TABLE 6.9

MISCIBLE GAS POTENTIAL
SANDSTONES VERSUS CARBONATES

	Technically Amenable	Technically Amenable and Profitable	Economically Dominant		Economically Dominant and Profitable	
	No. of Reservoirs	No. of Reservoirs	No. of Reservoirs	MMbbl	No. of Reservoirs	MMbbl
Sandstone						
CO_2	237	176	35	125	32	44
Hydrocarbon	237	197	148	1,074	112	1,006
Total	474	373	183	1,199	144	1,050
Carbonate						
CO_2	263	120	74	672	67	488
Hydrocarbon	263	171	189	516	98	346
Total	526	291	262	1,188	165	834

FIGURE 6.20: Carbon Dioxide and Hydrocarbon Miscible Potential Sandstone versus Carbonate Reservoirs

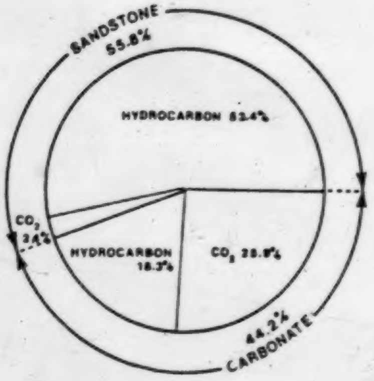
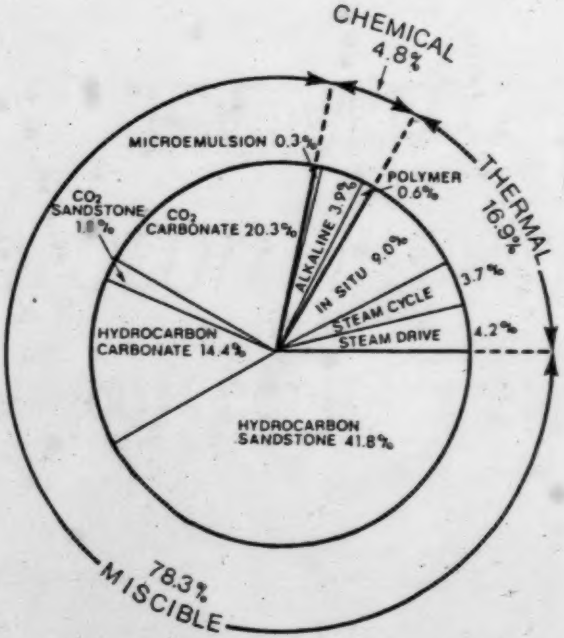


FIGURE 6.21: Shares by Recovery Process of Ultimate Tertiary Recovery



NOTE: The chart illustrates the proportion of ultimate recovery attributable to each process after economic dominance criteria have been applied. The potential for chemical flooding, for example, may be higher than indicated on the diagram but many of the eligible pools are less profitable under our assumptions regarding production and costs than if developed using the hydrocarbon miscible processes.

that of the sandstone group.

Costs of development and operation

Again the flow check was operative in a large percentage of reservoirs as shown in Table 6.10. Cost estimates are increased accordingly as 20 percent more wells are drilled. The percentage of reservoirs affected is significantly higher in the carbonate reservoirs (due to generally lower permeability), thus other costs and profitability were affected to a greater extent. This was a factor in reducing carbonate potential below that of the sandstone reservoirs.

TABLE 6.10

IMPACT OF FLOW CHECK BY PROCESS

	Economically Dominant No. of Reservoirs	Reservoirs With Increased Drilling Due to Flow Check			Percentage of Reservoirs Affected (%)
		Production	Injection	Total	
CO_2 (Sandstone)	35	11	22	22	63
CO_2 (Carbonate)	74	32	59	59	80
CO_2 (Total)	109	43	81	81	74
HC (Sandstone)	148	24	82	82	55
HC (Carbonate)	189	98	157	157	83
HC (Total)	337	122	239	239	71
Miscible (Total)	446	165	320	320	72

Undiscounted cost categories and the flow of these costs over time is set out in Figures 6.22 to 6.25. Fixed capital costs again emerge as a relatively small component compared to variable costs composed of operating costs and costs of materials.

FIGURE 6.22

UNDISCOUNTED COSTS BY CATEGORY
CARBON DIOXIDE MISCIBLE (BASE CASE)

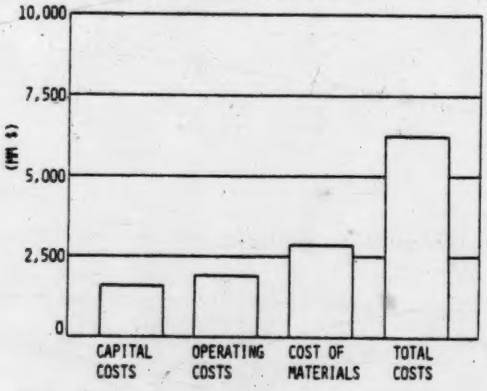


FIGURE 6.23

TOTAL COST BREAKDOWN, CARBON DIOXIDE
BASE CASE

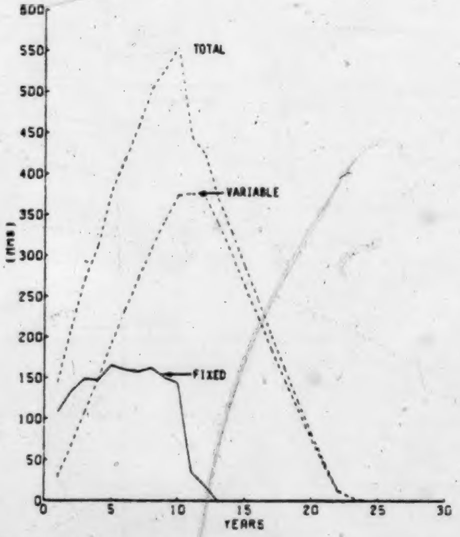


FIGURE 6.24

UNDISCOUNTED COSTS BY CATEGORY
HYDROCARBON MISCIBLE (BASE CASE)

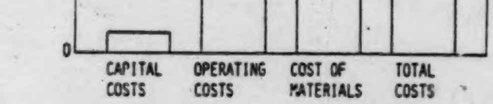
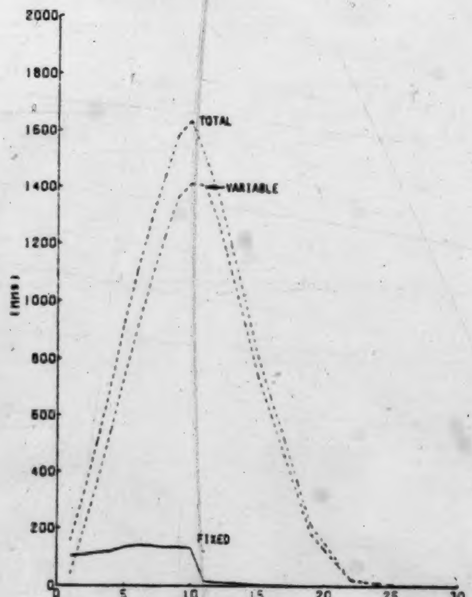


FIGURE 6.25

TOTAL COST BREAKDOWN, HYDROCARBON MISCIBLE
BASE CASE



Costs per barrel over the development period

The relation between supply price, original oil in place (OOIP), remaining oil in place (ROIP), and incremental recovery (IR) for reservoirs that would come on stream as market prices reach each pool's supply price is shown for each process in Figure 6.26. Table 6.11 shows the range of supply prices and the overall supply price for the two miscible processes in both carbonate and sandstone reservoirs. Supply prices versus incremental recovery with taxes and royalties included as a cost element are shown in Figure 6.27.

TABLE 6.11

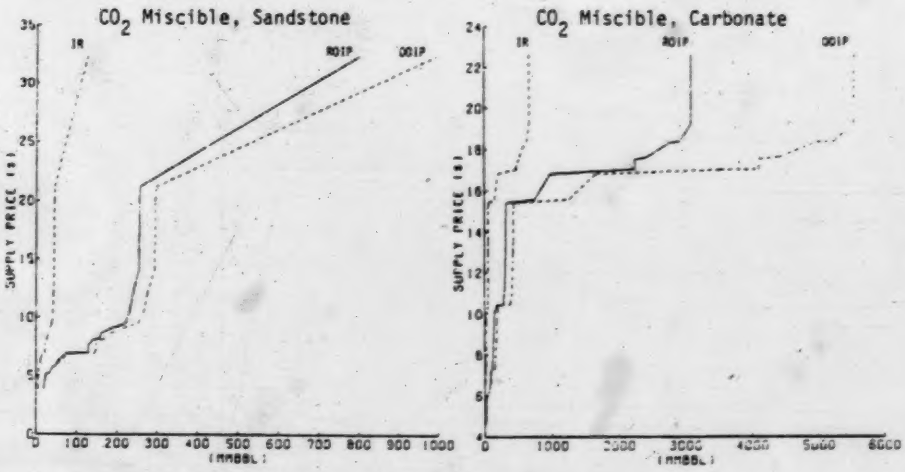
SUPPLY PRICES IN THE MISCIBLE GAS PROCESSES

	Overall Supply Price For Profitable Reservoirs Only ($/bbl)	Minimum Supply Price ($/bbl)	Maximum Supply Price ($/bbl)
Sandstone			
CO_2	7.67	3.90	32.34
Hydrocarbon	15.93	1.76	57.77
Carbonate			
CO_2	15.65	4.65	22.64
Hydrocarbon	13.47	7.65	82.02

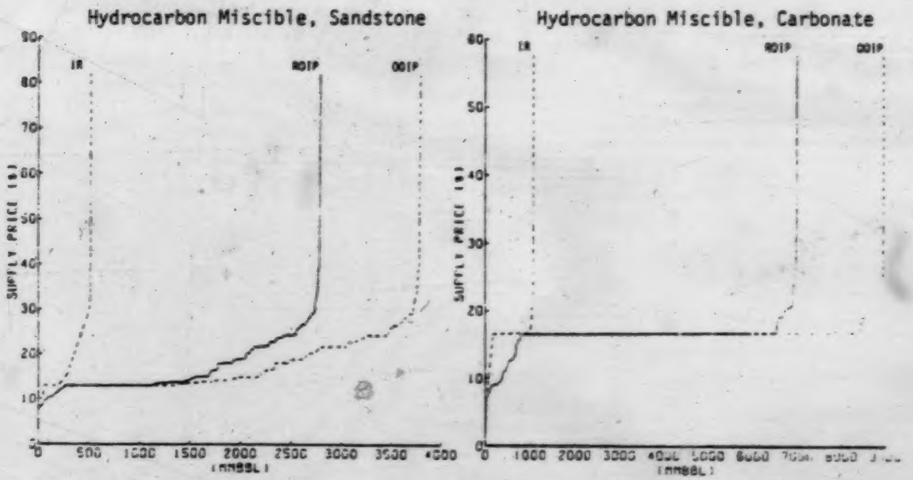
Social benefits and distribution

The social benefit from projects that would actually go ahead under present regulations is presented in Table 6.12. The company share of the economic rent is 39 percent for the hydrocarbon miscible process but only 26 percent for the carbon dioxide process. The

FIGURE 6.26: Supply Price and Incremental Recovery
IR: Incremental Recovery
ROIP: Remaining Oil in Place
OOIP: Original Oil in Place

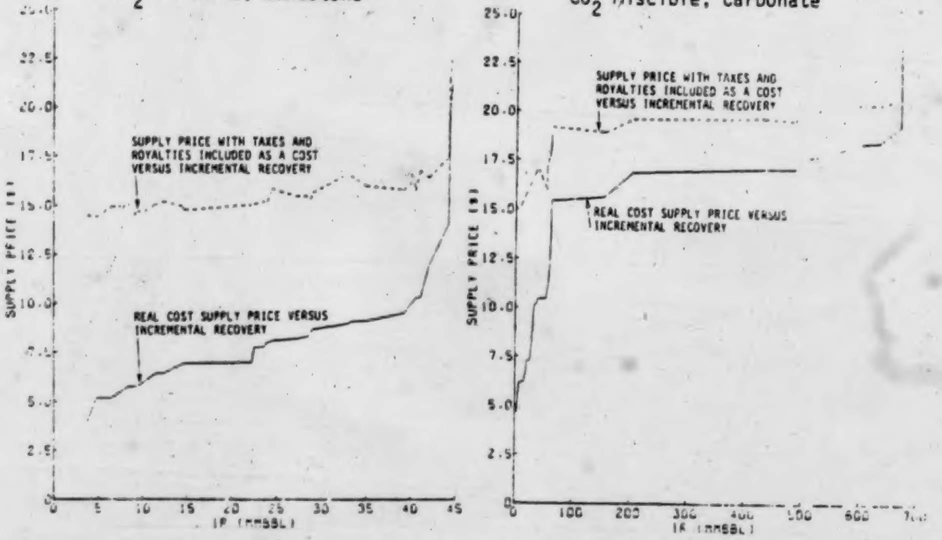

CO_2 Miscible, Sandstone

CO_2 Miscible, Carbonate


Hydrocarbon Miscible, Sandstone

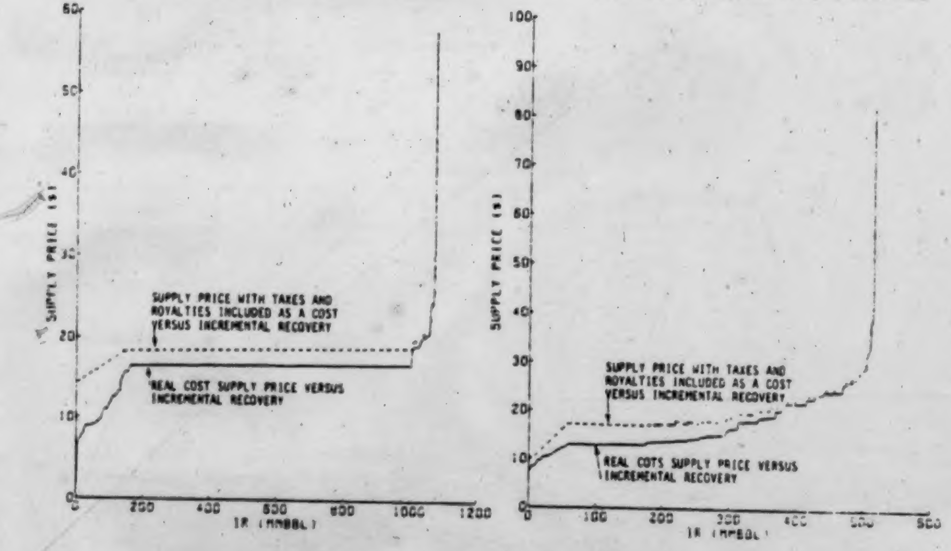
Hydrocarbon Miscible, Carbonate

FIGURE 6.27: Required Cost per Barrel of Additions to Petroleum Reserves Through Enhanced Oil Recovery



CO$_2$ Miscible, Sandstone

CO$_2$ Miscible, Carbonate



Hydrocarbon Miscible, Sandstone

Hydrocarbon Miscible, Carbonate

overall split for the miscible group, however, maintains the usual 35-65 division.

TABLE 6.12

REVENUE SHARES AND RATE OF RETURN AT $20 OIL PRICE
AND 8 PERCENT DISCOUNT RATE
MISCIBLE PROCESSES

	Realized Net Social Revenue ($MM)	Operator Net Present Value ($MM)	Tax Take ($MM)	Social Rate of Return (%)	Private Rate of Return (%)
Miscible	4,137	1,439	2,698	20	13
CO_2	1,227	315	912	18	12
Hydrocarbon	2,910	1,124	1,786	20	14

6.2.3 Thermal Processes

Incremental recovery

The thermal processes: steam drive, cyclic steam stimulation and in situ combustion, are economically dominant in 46 of the 643 reservoirs and profitable in 41 of these. They account for 90, 101 and 216 million barrels respectively in the base case with discounting and taxes. This is about 17 percent of the total potential.

However, the maximum potential for each process is higher than these figures indicate. If other processes prove infeasible for some reason, then thermal processes could be applied in more reservoirs.

The potential for steam drive is concentrated in two reservoirs which are dominant and profitable under base case assumptions. Therefore, the maximum potential for steam drive is the same as our forecast share (90 million barrels or 3.7 percent).

With cyclic steam stimulation, five reservoirs could profitably be developed but only one is economically dominant. Therefore the forecast share of steam cycle (101 million barrels) is less than the maximum possible. The maximum potential is 139 million barrels, an increase of 38 percent.

In situ combustion is economically dominant in 43 reservoirs of which 38 are profitable. But it could be used in 65 reservoirs of which 45 would be profitable at a $20 price, increasing incremental recovery by 206 million barrels.

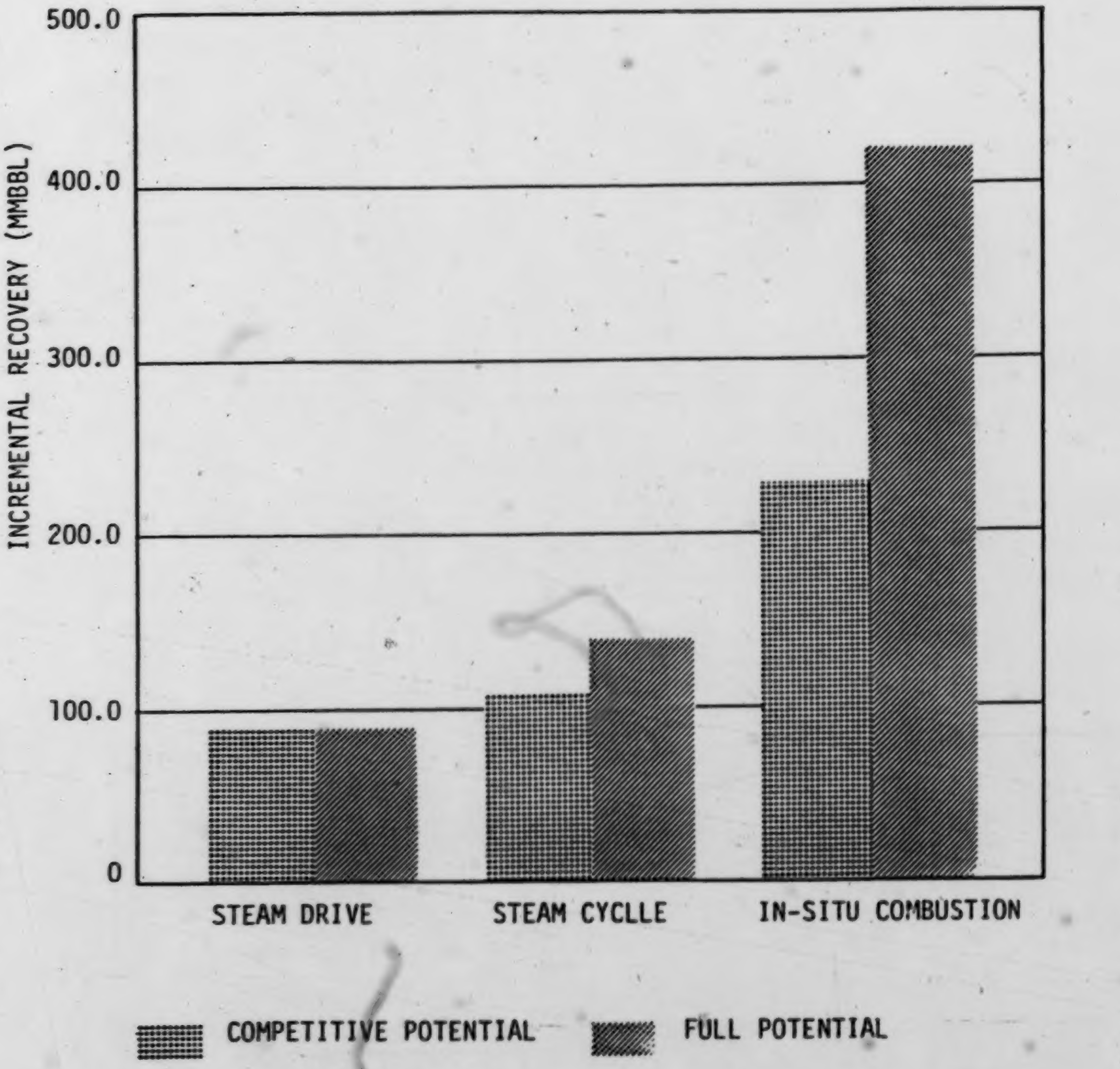
Competitive potential versus full potential is shown in Figure 6.28. These heavy oil projects do not in general compete with chemical or miscible projects so the extra potential of in situ is made up largely of the existing steam drive and steam cycle processes.

Production rates for the 10 year versus 20 year start up scenarios are shown in Figure 6.29. Steam cycle shows only one production profile because the pool comes on stream at the same time in both cases. The effect on steam drive production is likewise almost indistinguishable since all that happens is that the smaller pool is set back one year. The in situ combustion production flow is more noticeably affected by a 20 year implementation schedule, starting one year later, lasting one year longer, and with peak daily production rates 9 Mb/d greater than the 10 year case.

Costs of development and operation

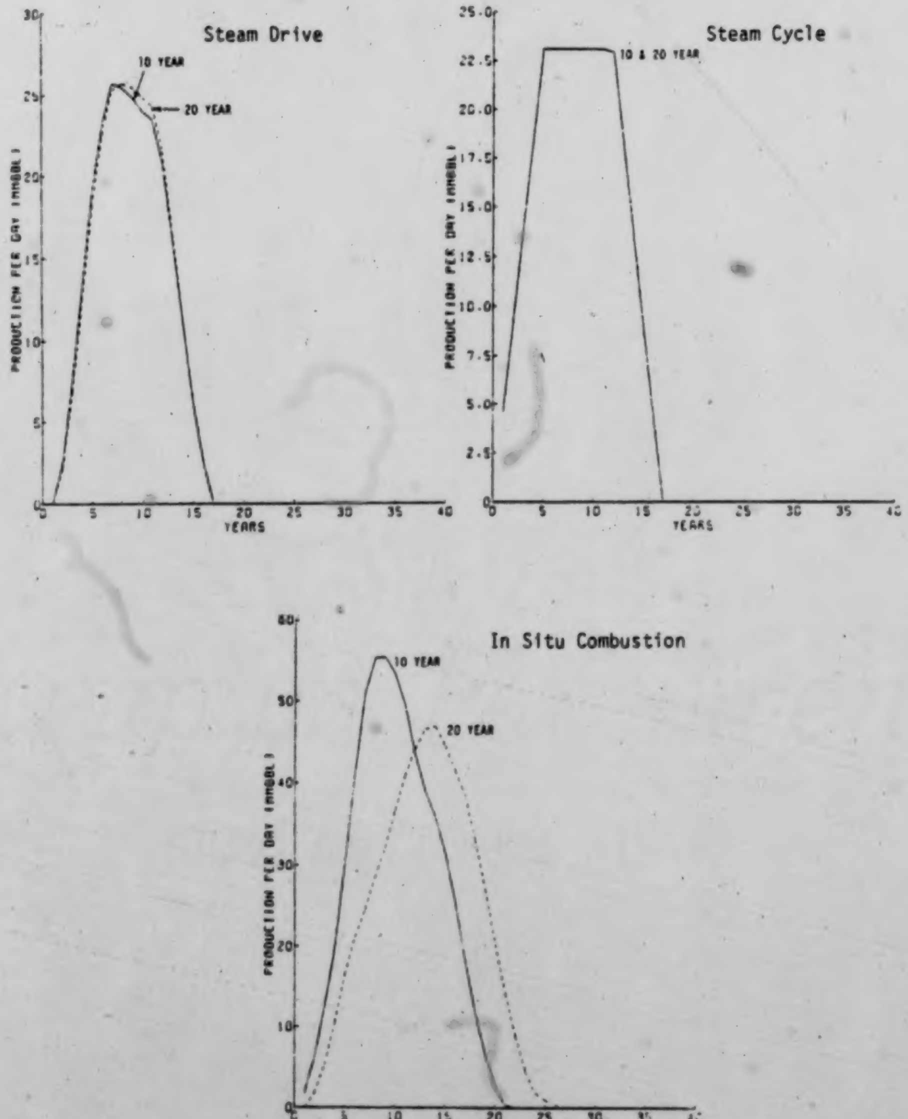
The flow check did not apply to the thermal processes because one of the parameters in that check is viscosity and the major impact of the thermal processes is to alter viscosity. Since we did not think it reasonable to forecast just how much viscosity would be changed and since we are dealing with quite small pattern sizes, we decided to

FIGURE 6.28: Competitive Potential versus Full Potential (Thermal Processes)



NOTE: Base case comparison of the 'competitive potential' of each process when it is limited by competition from other processes that dominate it economically with the 'full potential' of each assuming no competition from other processes.

FIGURE 6.29: Daily Production Rates
(10 year versus 20 years start-up period)



forego the flow check for the thermal group.

The cost breakdown for the thermal group is shown in Figures 6.30 to 6.37. The unusually large operating cost component of the in situ processes is due to the fact that compressor fuel costs were allocated to operating cost rather than to cost of materials. This had a significant impact on the results as discussed below.

Costs per barrel over the development period

Graphing the relation of supply prices and incremental recovery is not useful for the steam cycle and steam drive cases with only one and two pools respectively. The relationships are illustrated for the in situ combustion base in Figures 6.38 and 6.39. Table 6.13 presents the supply price range for all thermal processes. These supply prices, however, are not directly comparable to those of the other process groups because they take no account of the costs required to upgrade the quality of the heavy oils recovered by thermal processes to a state comparable to other processes. This is discussed further below.

TABLE 6.13

SUPPLY PRICE RANGE - THERMAL PROCESSES
(upgrading not included)

Process	Overall Supply Price for Profitable Reservoirs Only	Minimum Supply Price	Maximum Supply Price
Steam drive	7.22	6.48	7.42
Steam cycle	10.19	9.58	9.58
In situ combustion	12.09	3.99	14.99

FIGURE 6.30

UNDISCOUNTED COSTS BY CATEGORY
THERMAL PROCESSES (BASE CASE)

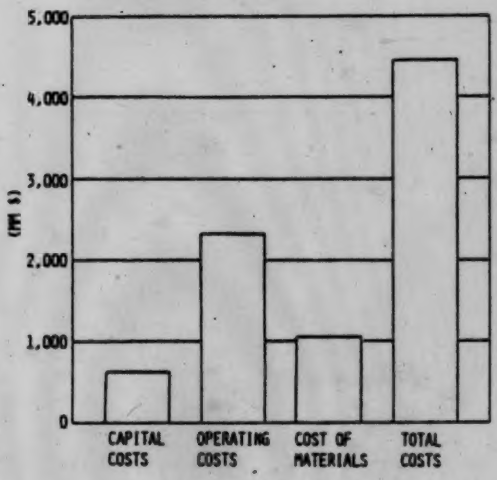


FIGURE 6.31

TOTAL COST BREAKDOWN, THERMAL PROCESSES
BASE CASE

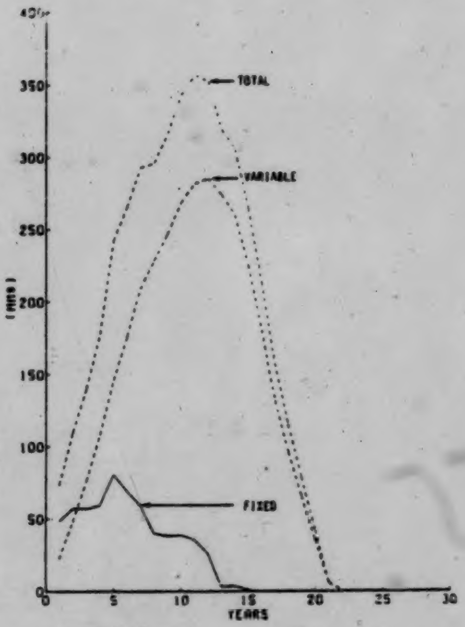


FIGURE 6.32

UNDISCOUNTED COSTS BY CATEGORY
STEAM DRIVE (BASE CASE)

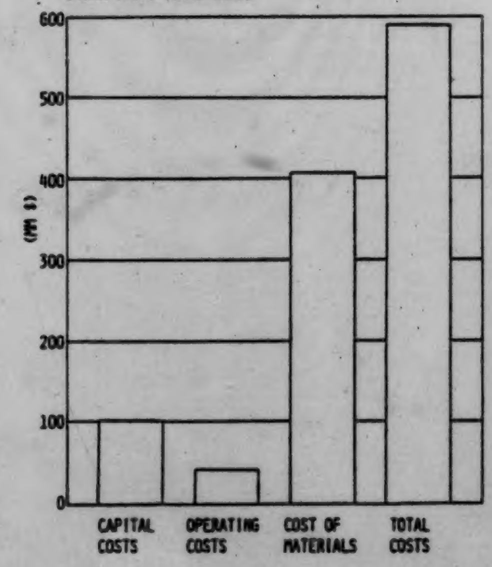


FIGURE 6.33

TOTAL COST BREAKDOWN, STEAM DRIVE
BASE CASE

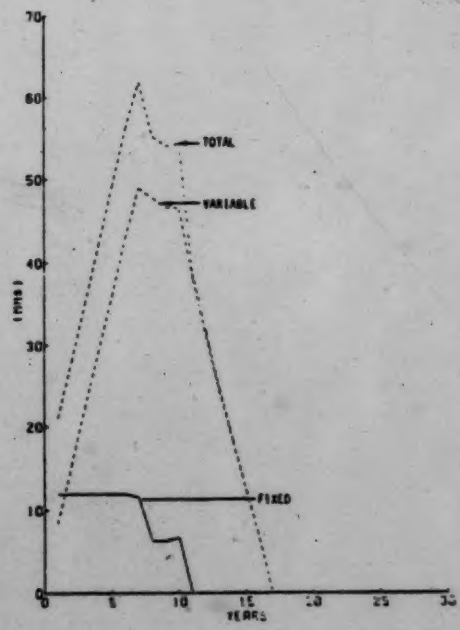


FIGURE 6.34

UNDISCOUNTED COSTS BY CATEGORY
STEAM CYCLE (BASE CASE)

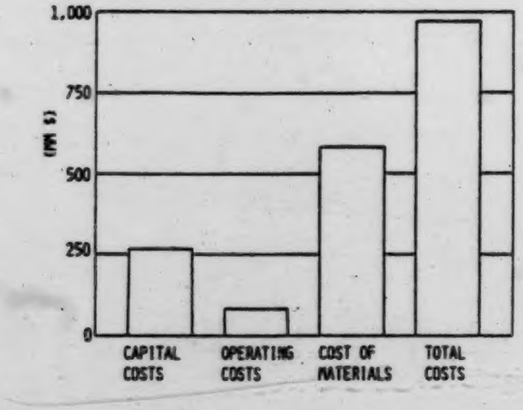


FIGURE 6.35

TOTAL COST BREAKDOWN, STEAM CYCLE
BASE CASE ,

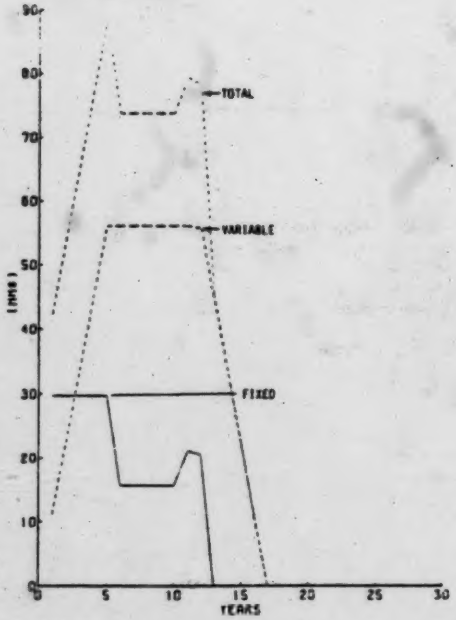


FIGURE 6.36

UNDISCOUNTED COSTS BY CATEGORY
IN-SITU COMBUSTION (BASE CASE)

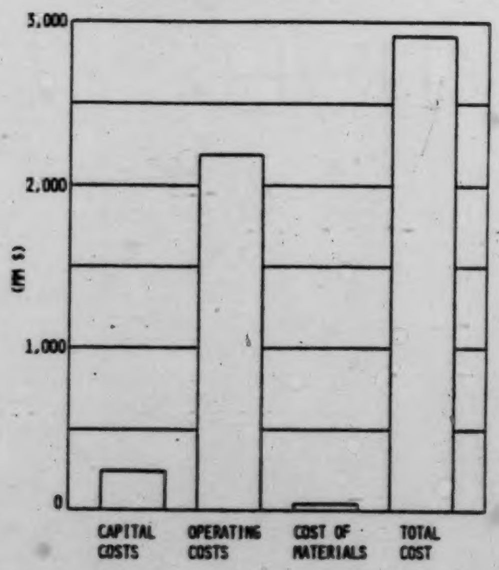


FIGURE 6.37

TOTAL COST BREAKDOWN, IN-SITU COMBUSTION
BASE CASE

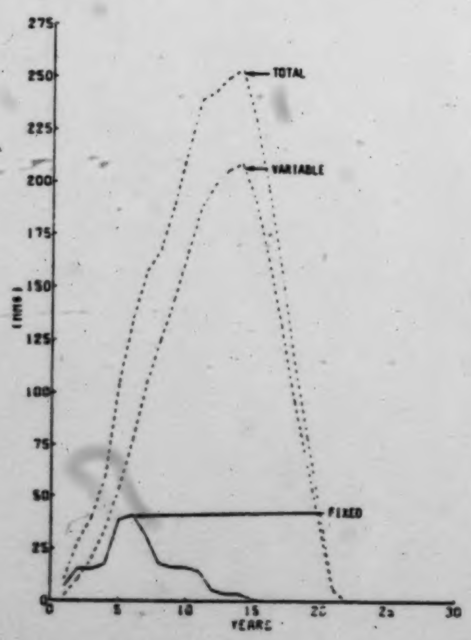


FIGURE 6.38

SUPPLY PRICE AND INCREMENTAL RECOVERY
IN-SITU COMBUSTION

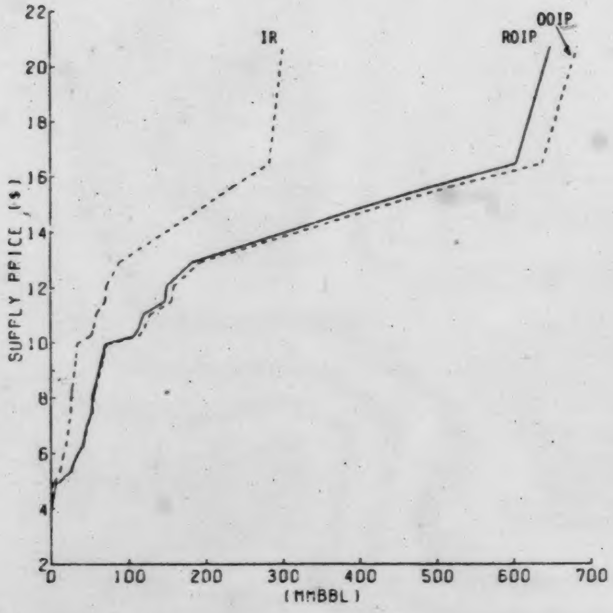
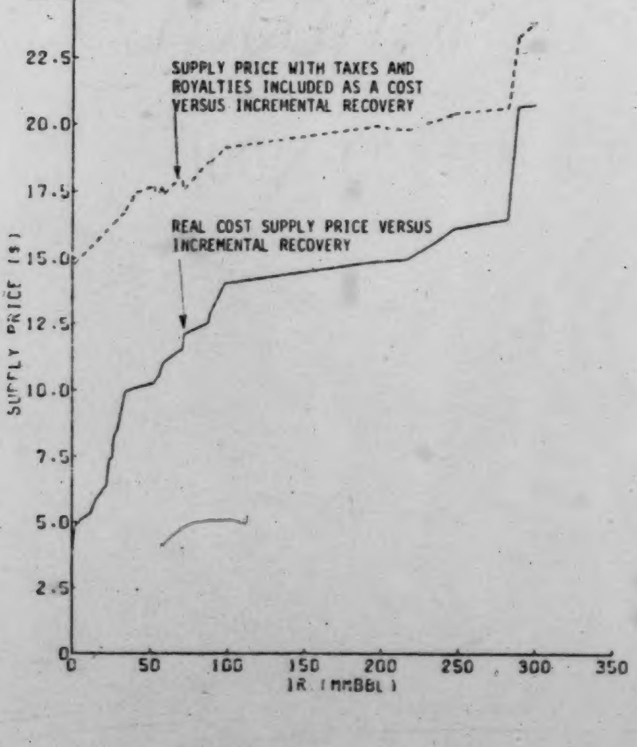


FIGURE 6.39

REQUIRED COST PER BARREL OF ADDITIONS
TO PETROLEUM RESERVES THROUGH ENHANCED
OIL RECOVERY - IN SITU COMBUSTION



Cost bias in the in situ model

The detailed analysis of costs for the in situ case uncovered a peculiarity that indicated some bias against the combustion process in the model itself. The allocation of 20 percent of operating costs as an overhead charge involved a particular burden because in the in situ model we inadvertantly allocated the cost of fuel required to compress the injected air to operating costs. Since the cost of fuel for the compressors is a large proportion of total costs, the overhead charge in the model was significantly higher than in the other models. Approximately 15 percent of total costs emerged as an overhead and administration charge whereas in other processes this charge was in the range of 2 to 8 percent. By reassigning the fuel charge to the material cost category we could reduce the overhead charge to a more reasonable level. This procedure would also, of course, lower total cost making more reservoirs profitable. But this in turn means that our original ranking of reservoirs would be altered. With lower costs, the in situ process would be expected to dominate in more than the 43 pools that emerged from the original ranking procedure.

This turned out to be the case. After re-ranking all pools, the number of dominant reservoirs in the in situ combustion process increased from 43 to 64, all of which were profitable in the base case. This increased the contribution of the in situ combustion process by 453 million barrels from 216 to 669 million barrels. Some of this came at the expense of other thermal processes, for example cyclic steam stimulation was eliminated. Thus, the increase in total thermal recovery was less than the increase in in situ combustion. Thermal recovery increased by 352 from 407 to 759 million barrels. Of this amount, 75 million was 'stolen' from non-thermal processes and 277 million represented an increase in ultimate recovery due to the lower costs.

However, this takes no account of the need to upgrade. Heavy oils can be used directly for some purposes such as asphalting, but such uses command a lower price. If we assign the same price to this oil as to the conventional medium-light oil, then we should take into account the fact that upgrading will be required. Estimation of the costs of upgrading was beyond the scope of the study, and so we considered a consensus estimate of $5 per barrel.[7]

Thus, our revised procedure involves two changes, the cost reallocation which lowers costs, and the upgrading charge which increases costs. Calculated in situ combustion supply prices for profitable reservoirs now range from $8.64 to $19.11. Thirty one reservoirs become unprofitable leaving 33 which represent 572 million barrels. However, both steam cycle and steam drive processes representing 190.6 million barrels are eliminated since they are dominated by the in situ combustion process under the new cost assumptions.

The overall impact of these changes is presented in Table 6.14. The thermal group increases its share by 6 percent, from 17 percent to 23 percent, at the expense of both chemical and miscible groups. Within the thermal group itself steam cycle and steam drive processes are eliminated under base case conditions. The net result in this case would be an increase in total thermal production of 165 million barrels, a decrease in chemical and miscible production of 75 million barrels for a net increase in tertiary recovery of 90 million barrels (3.75 percent of the 2.4 billion barrel estimate reported above).

Our analysis uncovered the modelling peculiarity in the over-

TABLE 6.14

IMPACT OF REALLOCATING IN SITU FUEL COSTS TO MATERIAL COST CATEGORY (THUS REDUCING OVERHEAD CHARGES) TO MAKE IT COMPATIBLE WITH OTHER PROCESSES

	BASE CASE Fuel Costs in IS Allocated to Operating Costs No Upgrading Charge				MODIFIED CASE Fuel Costs in IS Allocated to Material Costs (thus no impact on overhead calculation) $5 Upgrading Charge			
	Dominant Reservoirs	Dominant & Profitable	Incremental Recovery (MMbbl)	% of Total IR	Dominant Reservoirs	Dominant & Profitable	Incremental Recovery (MMbbl)	% of Total IR
Alkaline	82	75	93.6	3.9	79	72	57.5	2.3
Polymer	52	29	15.3	0.6	50	27	14.7	0.6
Microemulsion	17	6	6.6	0.3	17	6	6.6	0.3
Hydrocarbon miscible	337	210	1,351.8	53.7	328	201	1,332.6	53.3
CO_2 miscible	109	99	532.8	22.2	103	93	513.8	20.6
Steam drive	2	2	89.7	4.2	2	0	0	
Steam cycle	1	1	100.9	3.7	0	0	0	
In situ	43	38	216.1	9.0	64	33	572.0	22.9
Thermal	46	41	406.7	16.9	66	35	572.0	22.9
Chemical	151	110	115.4	4.8	146	105	78.7	3.2
Miscible	446	309	1,884.6	78.3	431	294	1,846.4	73.9
TOTAL	643	460	2,407.0	100.0	643	434	2,497.1	100.0

head calculation for in situ combustion projects before we had incorporated upgrading charges in the thermal models. The two changes partially cancel each other out; the initial supply price of $12.09 being reduced by only $1.76 to $10.33 per barrel. The ultimate impact on incremental recovery was less than 4 percent, with the thermal share increasing by 5 percent primarily at the expense of miscible gas. We did not view these results as sufficiently serious to warrant the time and costs required to repeat the entire set of sensitivity analyses.

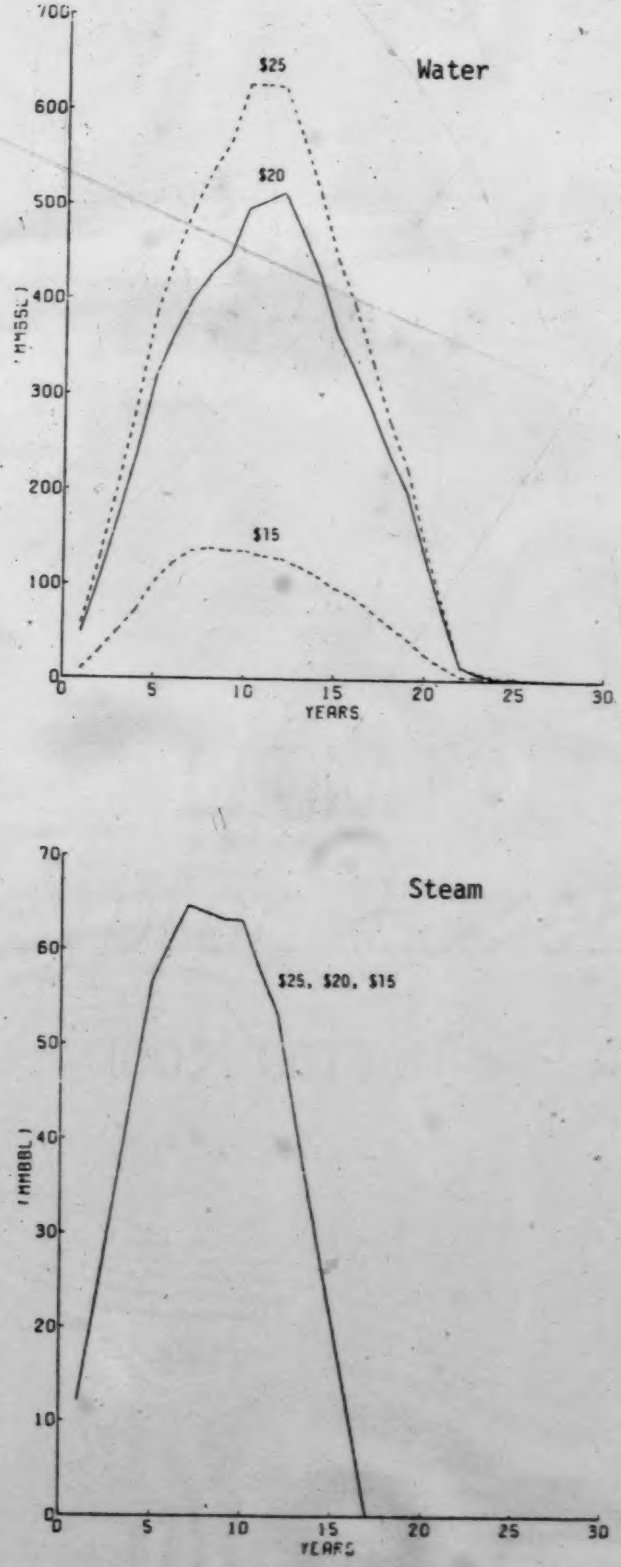
6.3 Potential Constraints on Full Scale Enhanced Recovery Efforts

6.3.1 Materials Requirements

Water

Water is required in several processes as a chase fluid and in the thermal processes to produce steam. The yearly requirements for these two uses are illustrated in Figure 6.40. The base case combined total requirement is about 7.3 billion barrels over the 28 year development period, with the peak yearly requirement of about 0.5 billion barrels occurring in 1992. Allowing for 50 percent recycling as an overall average, this means requirements from surface and ground water sources of 3.7 billion barrels with yearly usage peaking in 1992 at 250 million barrels. As shown in Figure 6.40, Water, this requirement varies according to the number of reservoirs developed. The maximum requirement (associated with the $25 price case) is likely to be for a total of 8.7 billion barrels peaking at 627 MMb/yr in 1990, an increase of 19 percent on the base case requirements. The minimum requirement, from the low price case, is 2.5 billion barrels, a 66 percent reduction from base case requirements.

FIGURE 6.40: Sensitivity of Injection Requirements to Changes in the Oil Price Assumption



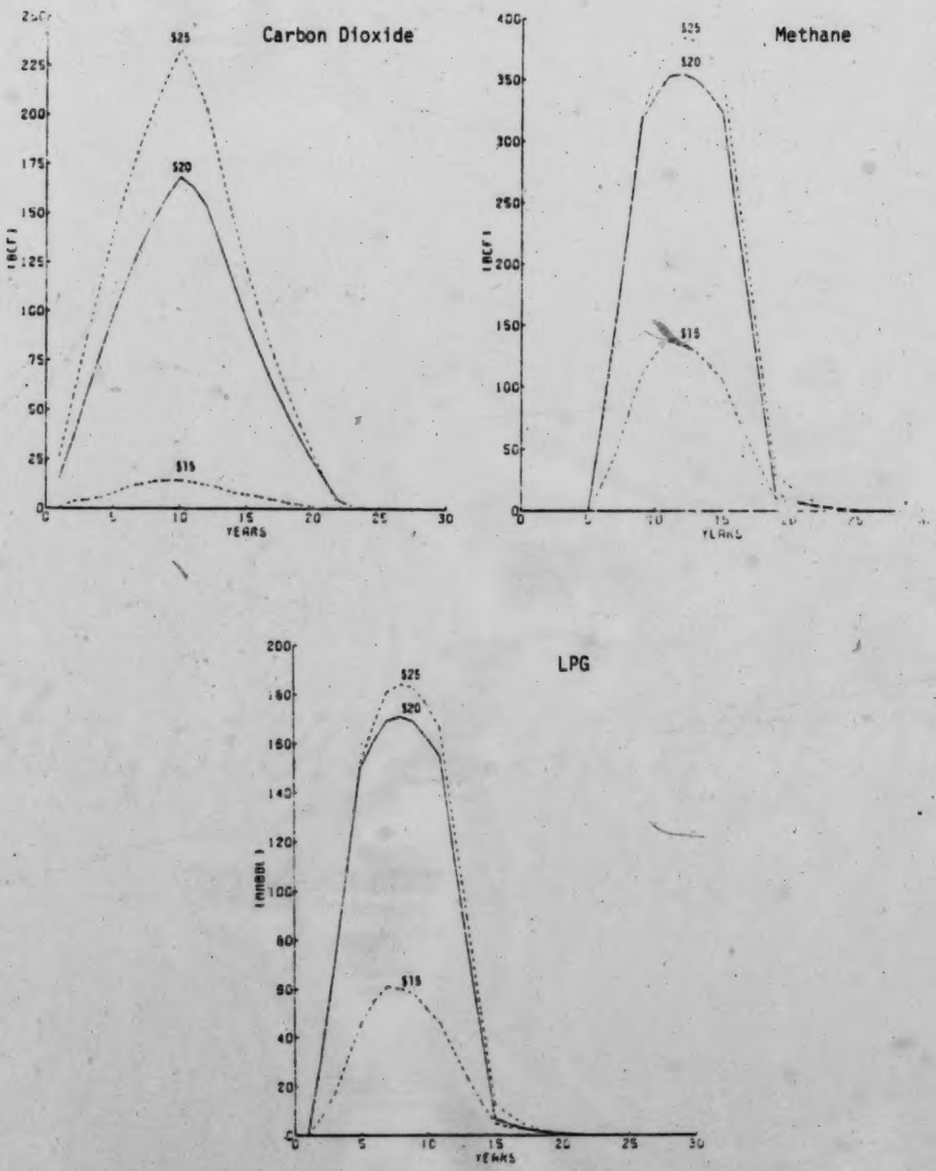
Realistic assessment of the relative importance of this requirement would require an evaluation of total water requirements in agriculture, industry and residential categories. Such an assessment is beyond the scope of this study and appeared unnecessary since the requirements are not that large to begin with and would be offset to a considerable extent by the concurrent decline in secondary recovery requirements. There is, however, a possibility that requirements in particular areas would strain available supplies at certain times of the year. This might occur, for example, in the southern part of the province where agricultural demand is particularly high. Further study of this question would be advisable if large scale initiation of tertiary projects occurs.

Carbon dioxide

The requirement for carbon dioxide is illustrated in Figure 6.41. Total base case requirements are for approximately 1.9 trillion cubic feet with yearly requirements peaking in 1990 at 169 billion cubic feet. Roughly 30 percent of this requirement might be recycled CO_2 leaving 1.3 trillion cubic feet required from external sources. This implies a peak annual external requirement of about 118 billion cubic feet in 1990 which is a daily requirement of about 325 million cubic feet.

A 1977 study done for Alberta Energy and Natural Resources by Saturn Engineering[8] concluded that although there are no natural sources of CO_2 in Alberta, significant quantities might be extracted from power plants, sour gas plants, and ammonia and hydrogen plants. The total potential amounts to over 630 MMscf/d of which 270 MMscf/d (from the power plants) involves currently unproven extraction methods.

FIGURE 6.41: Sensitivity of Injection Requirements to Changes in the Oil Price Assumption



This leaves some 360 MMscf/d potentially available from technically proven processes, which is enough to meet demand in the base case. The high price case might find supply tight in the peak year since proven supply would fall short by about 100 MMscf/d. This would not be a problem if extraction from power plants becomes viable and in any case it would only be a temporary problem when injection requirements peaked and could be ameliorated by rescheduling. The overall supply situation does not appear to constrain the CO_2 Process. Even in the event that the full technical potential of the CO_2 Process was realized, which would occur if competing processes were rendered not viable for some reason, the total CO_2 requirement of 2.7 trillion cubic feet could likely be met in future because of additional sources such as heavy oil upgrading plants, oil sands plants, and fertilizer plants.

Hydrocarbons

The time profile of required methane and liquid petroleum gas (LPG) is given in Figure 6.41. The base case requirement for LPG over 28 years is 1.6 billion barrels, the actual requirement being somewhat less since LPG are assumed to be completely recovered in the production phase. The methane requirement is 34.4 trillion cubic feet which also would be significantly reduced in actual operations since approximately 60 percent of the injected methane is recovered on average. As indicated in the figures, these requirements increase by only 8 percent in the high price case while being reduced by over 60 percent in the low price case.

The current abundant supply of natural gas is a major reason for renewed interest in the hydrocarbon miscible process and, without attempting a detailed demand-supply analysis, we accept the general opinion that hydrocarbon supply will not be an effective constraint.

Chemicals

Chemical requirements are shown in Figure 6.42. Since the chemical processes enjoy a relatively small share of potential recovery, these requirements are not of great significance.

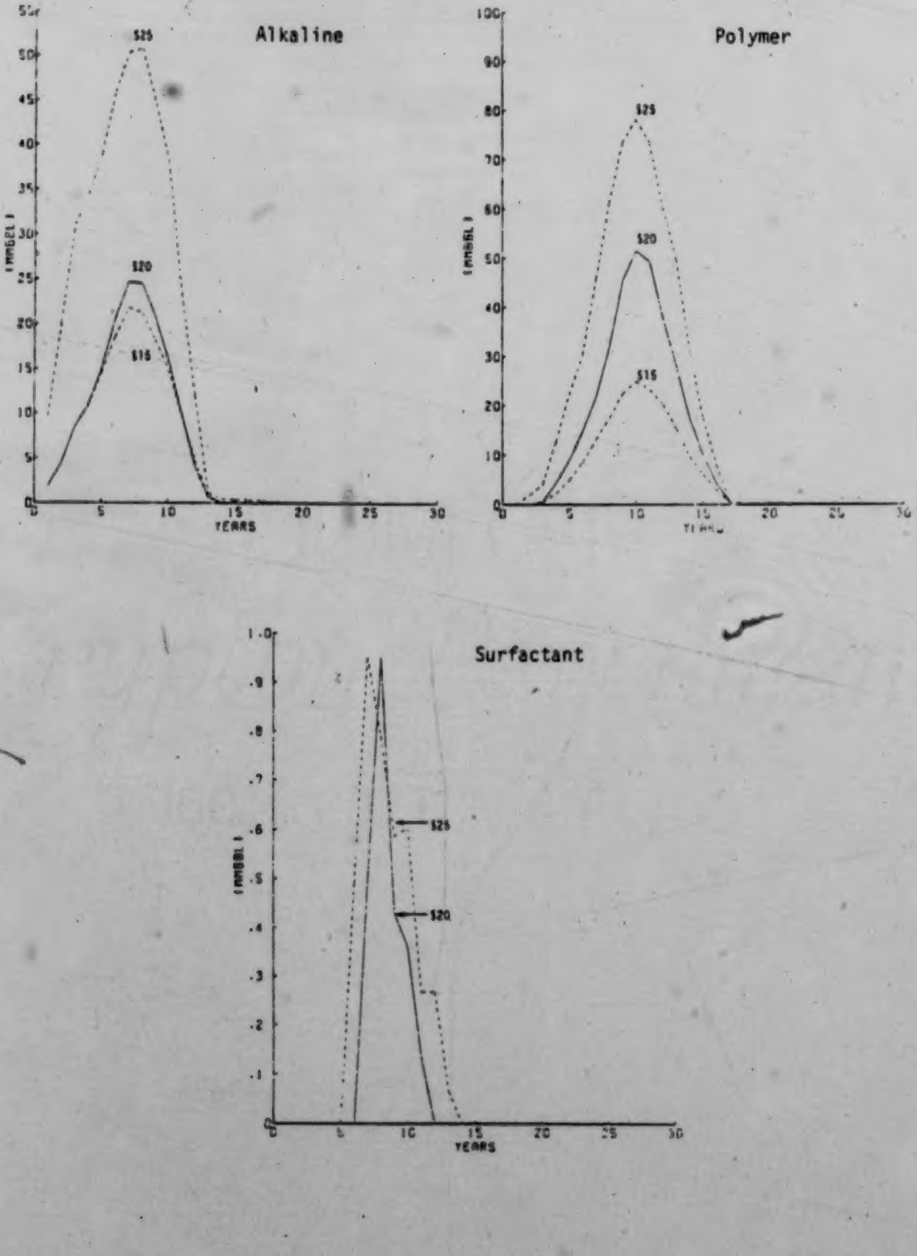
We have assumed the surfactant and polymer requirements to be met largely through imports. United States production capacity for sulfonates and polymers in 1976 was 600 million and 35 million pounds per year respectively.[9] The corresponding peak year requirements in Alberta from Figure 6.42, Polymer and Surfactant, would be approximately 22 million and 5 million pounds.[10] The polymer requirement might pose problems, especially if U.S. demand is significantly increased by their own tertiary efforts. Sodium hydroxide requirements would average approximately 5,000 tons per year which is less than one half of one percent of domestic production in 1976.[11] Even a considerable increase in the share of chemical processes would be unlikely to lead to supply bottlenecks because chemical plants have relatively short construction lead times (approximately 3 years).[12]

6.3.2 Manpower Requirements

Oil recovery is a capital intensive activity but the broad labour requirements for advanced enhanced recovery are themselves highly skill intensive. Reservoir and production engineers and technicians require special training in tertiary methods. Research chemists and chemical engineers with concentration in upgrading are also required. Full scale initiation of enhanced recovery projects will undoubtedly increase the demand for people trained in these areas though the increase is difficult to quantify.

A significant amount of the required training is likely to be provided in-house by operators themselves. However, the level of

FIGURE 6.42: Sensitivity of Injection Requirements to Changes in the Oil Price Assumption



activity suggested by the present analysis implies a need for a more substantial training effort. The introduction of adequate formal training at the university level is likely to lag somewhat possibly causing delays in implementing projects.

This would not be surprising since institutions generally respond only after a significant demand has been demonstrated. Ironically, the problem is likely to be even worse if a healthy economic environment prevails since competition for skilled personnel would be increased.

6.3.3 Implied Drilling Activity

The close spacing of tertiary processes implies a large number of injection and production wells. Assuming extensive secondary activities on 80 acre spacing means that a large proportion of these wells will be provided during waterflood operations. The time profile of drilling requirements for the three price cases is given in Figures 6.43 to 6.45. Total wells required in the base case is 27,361, about 80 percent of which would be provided during primary and secondary recovery operations. Total new wells required for tertiary recovery would be 5,554 with a maximum of 625 wells being drilled in 1987. Average yearly drilling requirements would be 327 per year over the 17 year period in which drilling is assumed to be carried out. This is easily within the capabilities of the drilling industry which in 1977 completed 800 development wells for oil and 2,527 for gas.[13] Of course, some of the secondary recovery development drilling would be going on at the same time. We did not estimate precisely the amount of development drilling for secondary recovery that might be required but if we assume that 50 percent of total requirements will already be provided (which is probably conservative) then new wells required for

FIGURE 6.43

TOTAL WELLS REQUIRED (WP) AND TOTAL WELLS DRILLED (WIP) FOR TERTIARY RECOVERY. ALL PROCESSES

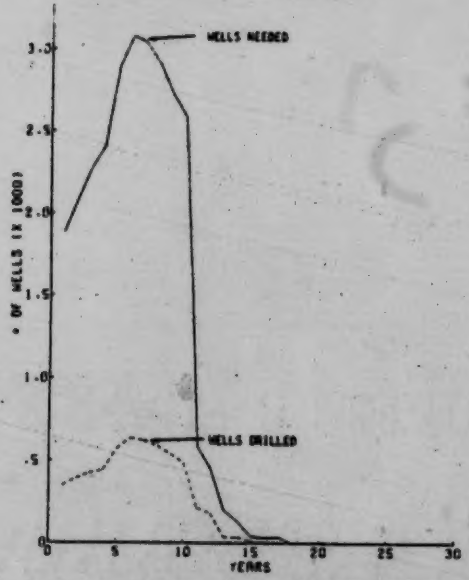


FIGURE 6.44

SENSITIVITY OF TOTAL WELLS NEEDED FOR TERTIARY RECOVERY TO CHANGES IN THE OIL PRICE ASSUMPTION ALL PROCESSES

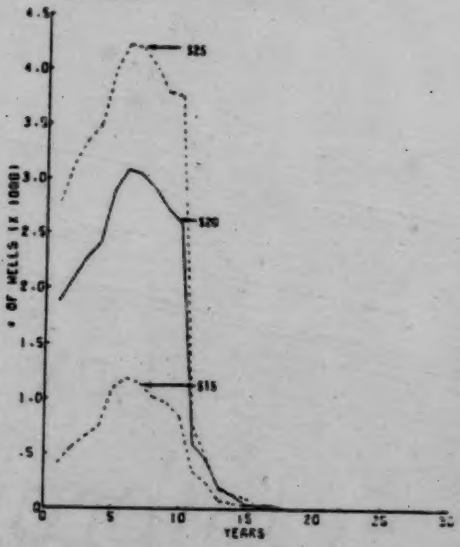
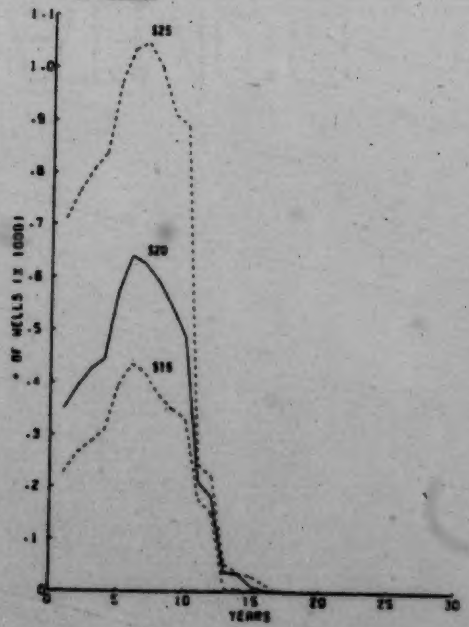


FIGURE 6.45

SENSITIVITY OF TOTAL WELLS DRILLED FOR TERTIARY RECOVERY TO CHANGES IN THE OIL PRICE ASSUMPTION ALL PROCESSES



secondary purposes would be about 11,000 in total or less than 650 per year.[14] Adding this to the estimate of tertiary wells required provides a rough estimate of total demand which does not appear to strain supply capabilities, particularly if we allow for a concurrent decline in exploratory completions.[15] Even the high price case involves at most 9,600 new wells for tertiary which is an average of only 565 per year. This admittedly rough estimate would seem sufficient to conclude that drilling requirements will not be a constraining factor to tertiary recovery activity.

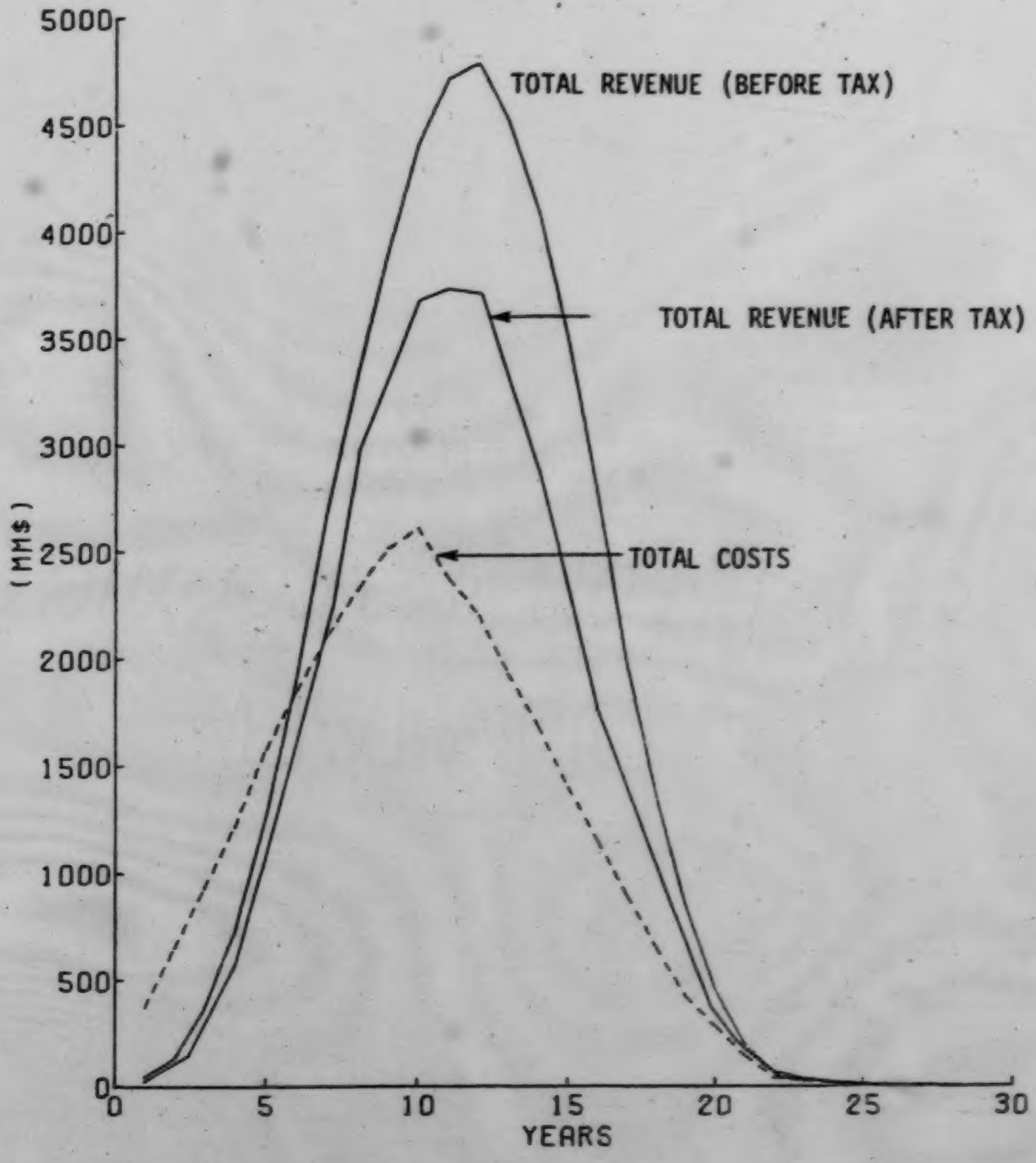
6.3.4 Financing Considerations

Requirements for financing are difficult to determine even for the general type of estimates of this section. For an individual project, financing may be required not only for 'front end' costs of capital and injection materials but also for operating costs until these are covered by production revenues. In the aggregate, the staggered nature of field development means that 'front end' costs will be incurred over most of the development period as individual projects are initiated. Operators will generally be involved in more than one project so that the revenues from mature projects may be used to finance the growth of young projects. This is simply a specific possibility of financing a new project from the general income of ongoing operations. In the past the capital and other investments of major oil companies have been approximately 80 percent internally financed, those of independents 50 to 65 percent internally financed. In aggregate internal funds accounted for about 73 percent of total sources of funds over the period 1960-1974.[16] This means that the actual external financing requirement will depend on the mix of operators (majors versus independents), the degree to which project financing is accepted in the financial community, and the quantity and characteristics of alternative investment opportunities. We can at best provide some perspective on the potential amounts of capital required for tertiary recovery in relation to the requirements of other areas of energy supply and other sectors of the economy.

The total costs of the level of tertiary development associated with our base case assumptions, in undiscounted 1978 dollars, is about $29.4 billion. Corresponding after tax revenues amount to $37.8 billion. The time profile of both after tax revenues and costs is shown in Figure 6.46. It is not until the seventh year that after tax revenues overtake costs in the aggregate (the projects begin financing themselves) so that if one operator was responsible for them all we might view cumulative costs in excess of revenues to that point as representing the requirement for financial capital. This amount is $2.6 billion. On the other hand, the fact that individual projects have different operators means that financing considerably in excess of this amount may be required. The maximum requirement would be for the total 'front end' costs (capital plus materials) which amounts to $17.1 billion (undiscounted). This requirement would only be realized if every project was carried out by an independent operator. Given the oil industry's historical tendency to finance not more than 30 percent of requirements from outside sources, a prospect made even more likely by the risk consideration of tertiary recovery, the capital market might be asked to provide from $1 billion to $5 billion for tertiary development. This may be compared with petroleum investment requirements to 1990 of about $40 billion (in 1975 dollars) of which about $8 billion may be met by external financing. However, the Federal Department of Energy, Mines and Resources, the author of these

FIGURE 6.46

REVENUES AND COSTS FROM TERTIARY RECOVERY



projections, investigated two different scenarios describing investment requirments and concluded that cash flow in the petroleum industry would be sufficient to cover the projected investments. They did note a potential distributional problem since some groups in industry may have excess funds while others may be short. But farm-ins and other techniques for transfer of funds that have been developed by industry are seen to be adequate to meet this need.[17]

Governments' share of undiscounted total revenues amounts to $10.3 billion. If they were to designate this revenue as being available for future tertiary development, the profile of revenues would appear as total revenue (before tax) in Figure 6.46. In this case revenues exceed costs in the sixth year and the cumulative excess of costs over revenues is reduced by $400 million to $2.2 billion. In either case, availability of financing cannot be viewed as a potentially serious constraint to tertiary development.[18]

6.3.5 Environmental Aspects of Tertiary Oil Development

This appraisal of the importance of potential impacts of enhanced oil recovery operations on the environment is quite general and its conclusion that such impacts are not likely to be significant should not be viewed as a suggestion that industry or governmental safeguards can be relaxed. Individual projects require explicit examination since specific impacts, even though localized, could involve significant and irreversible social or environmental costs. However, there are a number of reasons why, in the aggregate, environmental impact is unlikely to be a potent deterrent to development. First, the assimilative capacity of the environment should not be underestimated. The relatively small number of projects envisioned here would be geographically scattered over the province making environmental assimilation much less of a problem than if these projects were concentrated in a smaller area, as in the case, for example, with thermal development in California. Second, since these are in general 'tertiary' projects, much of the needed development, with its associated disruption, has already occurred. And finally, a lengthy history of experience with such problems has provided both industry and regulatory authorities with the necessary knowledge to ameliorate them. Nonetheless, ensuring that proper attention is given to potential problems requires continuing vigilance. The following discussion attempts to identify and comment on some of the major areas of concern.

The potential for impact of enhanced recovery operations on the environment exists in a number of areas. Transportation activities, on-site operations, and occurrences within the reservoir provide opportunity for adverse effects on surrounding land, water, air and biota.

Land impacts centre on field site development and use including necessary access roads. Accidental material spillage in transportation and at the site are inevitable but resultant damage would be quite localized and does not seem to pose a major problem. Another potential problem is land subsidence, which has been studied in primary recovery situations.[19] Generally it is felt that enhanced recovery will involve less problems in this area because the displacing agents are left behind in the reservoir. This is not true for in situ combustion which may cause some problems. But since these projects are generally not near residential areas the ultimate impact should be minimal. Land requirements may be important particularly in mountainous areas that provide scenic and recreational benefits. The impact is not straightforward since road provision may later provide access to more people and therefore be counted as a beneficial effect of development. But increasing concern with maintenance of what wilderness areas we have remaining suggests that, on balance, field development would be perceived as involving net social costs. However, since most of the required site development has already been undertaken at the primary and secondary production stages, land impacts cannot be considered a major drawback to enhanced recovery from established conventional reservoirs.

The only land problem of potential significance relates to the possibility of utilizing coal as an energy source in some projects. Here we have assumed that lease crude is used as the fuel but it is possible that significant development might be based on electrical energy from coal fired thermal generating plants. This situation would require evaluation of the effects of coal mining or stripping on the environment.

Effects on biota are also inevitable. Spillage and site access again affect the flora of a region in a localized manner. Fauna would be relatively unaffected by these operations except in cases of severe water and air pollution, discussed below. The possibility of significant noise pollution has also been considered particularly with respect to the steam generators and air compressors in the thermal processes. Where human population is proximate such activities will require muffling controls. Such controls may even be applied in areas where it is felt that local fauna may suffer. But in general the level of noise interference is small enough to make such provisions unnecessary.

A more significant possibility of pollution is associated with air quality. Chemical processes will have little direct effect on air quality but both miscible gas and thermal processes could have an impact. The primary concern associated with CO_2 injection is the possibility that hydrogen sulfide (H_2S), which is sometimes present in reservoirs, will be a product. H_2S is toxic and in combination with CO_2 would be likely to remain concentrated at ground level for extended periods, giving a hazard to animal and human life.[20] However, H_2S production may also be associated with conventional oil production and so industry is familiar with the problem and the safeguards.

Air pollution related to thermal processes also concerns the problem of hydrogen sulfide at the production stage but in addition there are a number of combustion materials such as SO_2, NO_x, hydrocarbons, CO and CO_2 associated with the generators and air compressors. These are primarily a problem in areas where air pollution is already significant such as certain heavily populated areas of California. However, mountain areas are susceptible to air inversions and this must be taken into account in some Canadian locales. Facilities for incinerating toxic substances, scrubbing the incinerated gas to reduce sulfur content, eliminating condensation plumes from the vent gas, and venting from tall stacks for maximum dispersion, were all included in cost estimates for thermal projects.

Water problems may relate to both surface water and ground water. The primary impact is on the quantity of water use but some qualitative effects are possible as well. Direct water pollution is most probable in the chemical processes and may occur through spills, well leaks, reservoir migration and inadequate disposal procedures. Since most of the activity is in areas previously waterflooded it is unlikely that operators would be ignorant of well problems or migration possibilities. A proportion of injected chemicals will be absorbed by the reservoir rock, chemicals produced with the oil will be processed in the refinery and chemicals in produced water generally get reinjected. Final disposal of water and chemicals is accomplished by reinjection with care to ensure ground water supplies will not be contaminated. Since the chemical processes represent a relatively small proportion of the total enhanced recovery effort, significant impacts on water quality are unlikely. Thermal pollution is possible if heated water is disposed of in surface pools. This can be controlled by cooling ponds or reinjection into the reservoir.

In summary, potential environmental disruption due to tertiary activity appears to be minimal particularly in relation to other sources of energy from non-renewable resources. This is accounted for by the fact that most surface facilities and roads are already in place and by the fact that a history of secondary recovery activities has educated industry in the problem areas. Some impact is inevitable but appears to be controllable under existing environmental regulations.

Footnotes

[1] Of course the maximum possible effect could only increase recovery by about 30 percent because of the technical limit of 3.1 billion barrels. However, the assymetry in results is significant since the upside constraint is never reached.

[2] An example calculation of elasticity for the thermal $15 to $20 case is as follows:

$$\frac{\text{change in Q}}{\text{average Q}} \div \frac{\text{change in P}}{\text{average P}}$$

which from Table 6.1 is:

$$\frac{20 - 15}{17.50} \div \frac{407 - 280}{343.5} = 1.3$$

It is necessary to base the calculation of percentage changes on the average of the initial and final amounts to ensure the result does not depend on the direction of change. For example, a $5 price change from $15 to $20 is a 33.3 percent increase. Whereas the same change from $20 to $15 is a 25 percent decrease. Both movements, however, represent a 28.6 percent change based on the average price of $17.50.

[3] F. M. Fisher, Supply and Costs in the U.S. Petroleum Industry, (Washington, D.C.: Resources for the Future, 1964). Edward W. Erickson, and R. M. Spann, "Supply Response in a Regulated Industry: The Case of Natural Gas," Bell Journal of Economics 94, Spring 1971. Edward W. Erickson and Leonard Waverman, The Energy Question: An International Failure of Policy (Toronto: University of Toronto Press, 1974).

[4] In economic terminology these would be excess profits or rents since the companies are already earning their 8 percent real (15 percent nominal) rate of return on capital.

[5] Notably the microemulsion process is eliminated completely at our low price of $15 per barrel.

[6] An anomalous pool with a supply price of $233.06 was ignored since it involves only 85,000 barrels.

[7] Canada, NEB, Oil Supply, p. 184.

[8] Saturn Engineering, "Estimate of Cost of Recovery of CO_2," prepared for Alberta Department of Energy and Natural Resources, November 1977.

[9] Gulf Universitites Research Consortium, Chemicals for Microemulsion Flooding in EOR, Report No. 159 (Bellaire, Texas: Gulf Universities Research Consortium, Feb. 1977), pp. 20-22

[10] This is for the base case. See Appendix D for the method by which the number of barrels of solution injected is translated into chemical requirements in pounds.

[11] 1976 production was 1,102,423 short tons. Canada, Statistics Canada, Manufacturers of Industrial Chemicals (Ottawa: Supply & Services Canada, 1976), Catalogue No. 46-219 Annual, p. 19, Table 8.

[12] Lewin and Associates, Inc., The Potential and Economics of Enhanced Oil Recovery, April 1976.

[13] Canadian Petroleum Association, Statistical Handbook (Calgary: Canadian Petroleum Association, 1977), Section 1, Table 5C.

[14] 80 percent of 27,361 is 21,888, half of which is 10,944 (644 a year for 17 years).

[15] In 1977 there were 360 oil exploration completions and 1,138 gas exploration completions.

[16] Canada, Department of Energy, Mines and Resources, Enhancing Energy Self Reliance (Ottawa: Department of Energy, Mines and Resources, 1977), Report EP 77-8, ch. 3.

[17] Ibid.

[18] A somewhat dissenting view has recently been offered by Dr. Norman A. White in an address entitled, "International Energy Financing--Implications for Canadian Energy Development," delivered to the 30th Annual Technical Meeting of the Petroleum Society of C.I.M. Basing his analysis on the development scenarios used by the Federal Department of Energy, Mines and Resources, and on trends in financing for the international petroleum industry, Dr. White suggests that the need for new and non-traditional sources of finance on the international scene will also be felt in Canada. Noting that Canada has been from 1976 to 1978 the world's largest country borrower on the international bond market, Dr. White cautions that lender's portfolio balance considerations and increasing international competition for funds may impose unexpected limits on Canadian international borrowing.

[19] M. N. Mayuga, and D. R. Allen, "Long Beach Subsidence," in Focus on Environmental Geology, ed., R. W. Pank (New York: Oxford University Press, 1973).

[20] CO_2 is non toxic though it could cause suffocation in sufficient quantity. But the main fear stems from the fact that it is heavier than air and might prevent associated H_2S from dispersing quickly.

CHAPTER 7

CONCLUSIONS AND POLICY IMPLICATIONS

7.1 Some Necessary Qualifications

In a study of this nature, an interpretation of results is bound to be conditioned not only by the nature of the special modelling techniques adopted but also by the research methods employed in estimating the critical parameters used in the models. Conclusions from the model relate to the amount and composition of the forecast potential, costs of development, benefits from the development and the distribution of those benefits, and the sensitivity of all results to changes in critical parameters. Implications from associated literature searches and discussions with representatives of industry and government relate primarily to the state of the art and the institutional and regulatory environment within which development must occur. The latter type of analysis is often as valuable, if not more so, than the former.

Conclusions derived from a modelling analysis have the advantage of objectivity within the assumptions of the models. That is also a disadvantage since the models, once they are constructed, are rather rigid structures. This is an aspect of the general modelling problem of simplifying reality in a realistic way. Here we have tried to ameliorate this problem with extensive sensitivity analysis. Of course, the assumptions that define the models are also open to critical evaluation which is why we have been as explicit as possible in setting out these assumptions.

This leads us to the first 'conclusion' of the analysis which is that all of the modelling results should be viewed as soft numbers, orders of magnitudes only. This warning is pertinent to any aggregate estimation procedure and in one sense our procedure makes such a warning less critical than it is for many kinds of commonly used modelling approaches that employ aggregated statistical techniques. This is because the very detailed process-specific engineering models used here allow for individual differences in technique and reservoir quality to a far greater degree than any aggregate statistical procedure would be able to do. Nonetheless, there are inevitably many areas of uncertainty that need to be kept in mind.

The uncertainty begins with the underlying data on which all results are based. ERCB estimates of original oil in place, recovery factors, and other parameters are probably as reliable as is possible given the present state of the art, but nonetheless, they are just estimates. This leads to, but is only one aspect of, the technical uncertainty associated with the screening procedure developed by the Petroleum Recovery Institute to identify potential candidates. Even in an actual field situation the process of accurate description of reservoir structure is difficult. The necessary restriction of our procedure to critical variables, which in some cases must be estimated by correlation with other variables, makes it even more tenuous. To some extent this works in both directions. That is, not only do we include some reservoirs that should not be included, we also may omit some that should be included. There is no a priori basis for assuming that one effect is more important than the other.

The next level of uncertainty is associated with the actual processes themselves. Knowledge of project design and operation is still at an early stage. This is made abundantly clear to non-technical researchers by the wide difference of opinion among practising engineers as to the most promising process or even as to the likely potential of tertiary recovery in general.

Economic uncertainty centres on the impact of changes in oil prices and unit costs on aggregate revenues and costs. It may be that the large price increases since 1973 have brought world prices close to an optimum level from the viewpoint of a monopolist or cartel in which case further increases are more likely to be in line with general inflation and less likely to come in unexpected jumps. Even so, uncertainty regarding tax and royalty policy at federal and provincial levels continues to complicate forecasting to some extent. On the other hand, development costs are more a source of uncertainty to modellers than to industry. The costs used in this study seem to be fairly reliable estimates as they have received reasonably wide distribution within industry without noticeable repercussions.

Thus the major areas of uncertainty are technical and almost impossible to quantify. We have allowed for this uncertainty in evaluating the recovery activity by the implicit inclusion of a risk premium in the discount rate, by a generous allowance for overhead which allows costs of failure in two out of ten pilot tests, and by the arbitrary reduction of calculated incremental recovery by 8 percent (which on four billion barrels amounts to close to a third of a billion barrel allowance). Whether or not these are adequate allowances is difficult for anyone to say. They seem reasonable but because of the embryonic stage of development to which the relevant technology has only recently evolved they could be quite inadequate. Yet, the research effort is justified as, we hope, will be made clear from the nature of the conclusions that do emerge from it.

One aspect of the analysis requires discussion before the general conclusions are presented. The real rate of discount used to translate all results into present value terms was 8 percent. This may be interpreted as the rate of return deemed sufficient and appropriate to induce industry to allocate its resources to the activity of enhanced oil recovery. This rate was cited by Lewin and Associates as the historical petroleum industry real rate of return on investment.[1] If we assume a 7 percent rate of inflation, an 8 percent real return approximates a 15 percent nominal return which was precisely the return that was being used by several oil companies contacted in mid-1979. On the other hand, a study by the Economic Council of Canada suggested that the average overall historical real rate of return to capital in Canada over the period 1965 to 1974 was about 10 percent.[2] Since the present study incorporates some allowance for risk apart from the premium in the discount rate, it is arguable that the lower assumption used here is more appropriate.

Although 8 percent real and 15 percent nominal may appear somewhat low under conditions existing in late 1979 (the Bank of Canada's lending rate to commercial banks has been at 14 percent since October 1979) it must be remembered that the nominal interest rate is viewed as a policy instrument and is subject to severe short term fluctuations in response to economic conditions. Moreover, if we chose here to suggest an inflation rate of 10 percent would prevail over the study period, then a nominal rate of 18 percent would be associated with our chosen real rate of return of 8 percent. Therefore, we feel confident with a real rate of 8 percent as a basis for analysis but whenever convenient we have shown how results vary when the rate of discount is altered.

7.2 General Conclusions

7.2.1 Incremental Recovery and Production

Of the 36.1 billion barrels of conventional oil estimated to exist in Alberta in 1976, 32 percent (11.4 billion barrels) will be recovered by primary and secondary production processes leaving 24.7 billion barrels remaining in the ground. 16.7 billion barrels, 68 percent of the ultimate remaining oil in place, lie in reservoirs that show some affinity for enhanced recovery. This is the technical tertiary target which, if it was fully exploited under production assumptions used here and without regard to cost, would yield 3.1 billion barrels.

This 3.1 billion barrels is not, however, the amount of oil recovery that can be expected under foreseeable economic conditions. Our base case forecast assumed a $20 price for oil at the wellhead and allows industry an 8 percent real return on investment (which approximates a 15 percent nominal return). If we assume no taxes and royalties are levied against these projects, or more correctly, if we assume any taxes and royalties assessed are set at some optimal level that does not affect the viability of any project from a private point of view, then the maximum economic recovery is estimated here as 2.7 billion barrels. Moreover, if we assume the present rules governing tax and royalty collection, our forecast of expected additions to oil supplies from enhanced recovery activities in Alberta reservoirs is reduced by 300 million barrels to 2.4 billion barrels. This is approximately 10 percent of the ultimate remaining oil in place after primary and secondary recovery (24.7 billion barrels as forecast by the Alberta Energy Resources Conservation Board) and 14 percent of the technical tertiary target (16.7 billion barrels) established by the screening procedure used in this study.

Reductions in costs or increases in oil price could increase the amount of economically recoverable oil. However, the current level of technical understanding of the various recovery processes, the state of the art, is reflected in the screening procedure used at the initial stage of the analysis and in the methods used to estimate the technical incremental recovery for reservoirs that successfully passed the screening test. This assumed level of understanding implies a technical limit on enhanced recovery potential. That is, regardless of how favourable prices and costs might become, the maximum recovery potential is limited to 3.1 billion barrels. This is 19 percent of the technical target or 13 percent of the ultimate remaining oil in place after primary and secondary recovery efforts. Greater recovery would require basic technological advance in the various production processes.

Extrapolation of the Alberta recovery potential (2.4 billion barrels) to Canada results in a potential of some 4 billion barrels, with most of the increase over Alberta attributable to the heavy oil deposits in Saskatchewan.

Under the assumptions of our model, the Alberta potential would be produced over 28 years with an average yearly production of 86 million barrels (235,000 barrels per day). This production would, however, begin slowly, build to a maximum of 240 million barrels per year (or 656,000 barrels per day) in 1992, and taper off gradually in the first decade of the twenty-first century. Canadian production, from areas other than Alberta (primarily Saskatchewan), is likely to be increased by two thirds of these amounts.

In Alberta about 78 percent of the potential recovery will come from the miscible and immiscible gas processes, 17 percent from thermal processes and 5 percent from chemical processes.

For Canada as a whole these percentages become miscible 61 percent, thermal 36 percent, and chemical 3 percent. These shares are rather invariant to changes in critical parameters once the marginal reservoirs have been brought on stream.

7.2.2 Costs and Supply Prices

The cost analysis indicates that the generally assumed importance of 'front end' costs (usually capital equipment) applies to these projects but an even more significant component of costs is attributable to injection materials. Front end costs in general refer to costs that must be incurred before production begins. In our models production usually does not begin until the second year of operation and in some cases (microemulsion and miscible gas floods) not until the third year. However, all costs are allocated to the year in which they would occur in actual operation. Capital costs are required before operations begin and are allocated to year one for each unit of development. There may be several units in any reservoir. In most cases initial injection material costs are also incurred in year one. But materials costs, in general, continue to be incurred throughout the life of a project (even after production begins) and are therefore not 'front end' costs in the same way as capital costs are. The effect of increasing individual cost components revealed a very high sensitivity of performance to increases in materials costs, particularly in the miscible processes. A 25 percent increase reduced recovery by 64 percent. The reduction in the net social value of this oil is considerably smaller (41 percent) indicating the eliminated reservoirs were high cost projects. Nonetheless, the impact is significant.

The average discounted revenue per barrel required over the entire development period to allow recuperation of all costs including an 8 percent real return to capital investment is referred to as the 'supply price'. It depends on the productive characteristics of each reservoir and, therefore, shows considerable variation over the 643 economically dominant projects analyzed here. It ranged from $1.76 per barrel in a highly productive hydrocarbon miscible project to $96.05 per barrel in a relatively poor polymer project.

By treating all profitable pools in a particular process as part of an overall project, we are able to calculate a supply price for that process which is essentially an average of individual reservoir supply prices weighted by each reservoir's contribution to total recovery. These are as follows for the processes investigated here. These supply prices do not include the upgrading costs for heavy oil that would be required for steam drive, steam stimulation and in situ combustion.

	Weighted Average Supply Price (profitable pools only)	Range of Supply Prices by Reservoir (including unprofitable pools)
	1978 dollars per barrel	
Steam drive	7.22	6.48 - 7.42
Steam stimulation	10.19	10.19
In situ combustion	12.09	3.99 - 14.99
Alkaline	6.64	3.02 - 44.79
Polymer	12.70	4.08 - 96.05
Microemulsion	17.68	16.15 - 64.87
Carbon dioxide miscible	14.98	3.90 - 22.64
Hydrocarbon miscible	15.32	1.76 - 82.02

Similarly, if we treat costs from all projects as part of a single project we calculate an overall supply price for tertiary activity at $13.90 per barrel. This amount compares favourably with recent estimates of a number of alternative fuel sources (oil sands, coal liquefaction, etc.) which range upward from $20 per barrel depending on the particular assumptions adopted.

7.2.3 The Value of Production and Its Distribution

The potential net value of tertiary production to society is calculated as the value of the oil minus the value of the resources used up to recover the oil. The present value of the 2.7 billion barrels that would be produced if the tax system had no impact on production is $26.1 billion (in 1978 dollars). The real resource costs required to produce this oil are $18.7 billion so the present value of the net social benefit to Canada would be $7.4 billion.

Since the tax system interferes somewhat with production activities (by making some reservoirs unprofitable from an industry point of view) the 'realized' net social benefit is somewhat less than the 'potential'. Realized production of 2.4 billion barrels provides (in present value terms) social revenue of $23 billion with associated costs of $16.1 billion yielding a net social value of $7 billion under current tax and royalty regulations. The elimination of 300 million barrels of oil with a net present value of $400 million is a measure of the real cost of the tax system.

The realized net social benefits are distributed through taxes and royalties between two levels of government, as representatives of the owners of the resource, and industry, as the agent of production. If industry is receiving its required rate of return (assumed here as an 8 percent real return) then it is not necessary to allow it to receive any of the net benefits. In practice, however, companies would receive about 35 percent of the net benefits largely because the tax and royalty regulations currently in place do not appropriate the total net value for the resource owners. In view of the fact that individual reservoirs exhibit wide variation in productivity, it is difficult to design and implement a uniform collection system that appropriates the total net value for the resource owner without seriously impairing production effort.

A qualification to the paragraph above is in order. The value of the social benefit is dependent on the private rate of return required by industry. Our base case assumption is that this real required rate of return is 8 percent, which leads to our estimated net benefits of $7 billion of which industry gets 35 percent. But if we allow industry a real rate of return of 15 percent (22 percent nominal if inflation is 7 percent), the net social benefits are reduced to $2.9 billion of which industry receives only 13 percent. We believe that 8 percent is a fair rate of return especially when some portion of risks are allowed for in other ways, but this is a value judgement, an area in which reasonable people might reasonably disagree, especially when risk is difficult to quantify.

7.2.4 Some Principal Results of Sensitivity Analysis

The assumptions in our models relating to the size of the production unit, the length of time over which production or injection would occur, and the percentage of production and injection that would occur in each year, implied in each project a particular rate of oil flow through the reservoir. On the other hand, there is a maximum theoretical flow rate that can be determined with knowledge of the physical characteristics of the reservoir and the oil contained in it. In order to ensure that this theoretical limit was not exceeded, we incorporated a check on implied production and injection rates. Whenever these rates exceeded the theoretical limit the number of wells drilled was increased, increasing the costs of development for that reservoir.

This technical check on the flow rates implied by the assumptions of the models was operative in a significant number of cases (i.e., the implied production or injection was greater than the reservoir could handle). The problem might be circumvented in the field because project design would be tailored to specific reservoirs. The result does, however, indicate a potential limitation of estimation procedures in other studies that did not incorporate this check and may therefore have significantly underestimated development costs.

All results were based on an assumed 'project initiation' period of 10 years beginning in 1980. A certain percentage of projects (ranked by profitability) are started in each year. The base case was repeated using a 20 year initiation period with very little impact on the results. The overall supply price increased by ten cents, the present value of after tax net revenue to industry was reduced by 7.6 percent, and although production rates for individual processes were sometimes altered significantly, overall rates of production were altered very little. The maximum daily rate is again achieved in 1992 and is only 10 percent less than before.

Detailed sensitivity analysis was carried out with respect to changes in four critical parameters, the price of oil, development costs, the assumed recovery factor, and the general assumptions on pattern size used in the production analysis. The purpose of this was partly to establish a range of probable results but also to provide additional description of the set of projects under consideration.

The results indicated the existence of a number of high cost pools that would not be profitable if the price over this development period was $15. This 'development plateau' is characterized by a particularly heavy impact of the tax system. Selective reduction in taxes in the $15 price case would increase recovery by approximately 1 billion barrels (116 percent) whereas in the $20 to $25 price cases tax alterations would increase recovery by only 12 percent and 1 percent respectively.

The development plateau is concentrated in the miscible group, which exhibits a marked response in production to a change in price from $15 to $20 per barrel. The chemical group on the other hand includes very productive reservoirs at the $20 price and a $5 reduction has little effect on these good prospects. The implication of this is that at prices approaching $20 per barrel the chemical projects are a more reliable group than miscible ones. The marginal reservoirs included in the base case miscible group would be affected to a greater degree by adverse price, tax, or cost developments than would the chemical group.

Supply elasticities are calculated in the study. The elasticity related to all processes over the $10 price range investigated here is 2. Comparing this with the unitary elasticity of supply of conventional oil suggests that enhanced oil recovery is about twice as responsive to price increases as conventional oil recovery. This is a rough comparison only, since the unitary elasticity estimate for conventional oil was made at lower price levels and might well be higher for the high prices (and large price changes) used in our calculation.

Analysis of individual process results indicates that the potential of individual processes for profitable production generally exceeds our forecast potential which is based on the optimal production mix. The clearest illustration of this comes from comparing the hydrocarbon and carbon dioxide miscible processes since these both apply to the same set of reservoirs. Carbon dioxide flooding turns out to be the best choice in 99 reservoirs whereas hydrocarbon floods are best in 210 reservoirs. If the carbon dioxide process turned out to be impractical in Alberta (say due to inadequate sources of CO_2), it is likely that all 99 reservoirs could be developed with the hydrocarbon miscible approach. Thus, there is some substitutability between processes which would partially offset any adverse developments in a particular area.

7.2.5 Potential Constraints

A rather limited analysis of possible constraints is presented in the study. There appear to be no operative constraints on enhanced recovery operations with the possible exception of technical expertise. One reason for this is that tertiary recovery will essentially follow secondary recovery effort. Drilling, manpower, and water requirements are thus declining in the latter case as they increase in the former. Chemical supply might have been a constraint if the chemical processes had captured a larger share of the potential but since they only account for about 5 percent of the total there should be no problem. External financing requirements should not strain the capital market unless early ventures indicate an extremely high level of risk. Environmental impact is relatively small in relation to almost any other energy development area and most impacts are reasonably well understood from primary and secondary operations. Water supply may pose problems in some areas due to conflicting demands and should be the subject of further research. The trend in supply of technically skilled people is difficult to evaluate. Institutions respond to increased demands with a lag which suggests that in house training is likely to be a more significant source of expertise for some time.

7.3 Policy Implications

7.3.1 The Nature of the Energy Crisis in Canada

For many industrialized countries the energy crisis is largely a question of ensuring adequate supply. Japan and, to a lesser extent, Germany face the prospect of increasing dependence on foreign sources at costs largely beyond their control. In Canada the question is at present more one of cost. To what extent should our relatively low cost sources of energy be utilized intensively today? What higher cost sources do we have available? At what stage should relatively higher cost sources be phased in?

On strictly economic grounds the latter question has an unambiguous answer. The most efficient exploitation of the resource base utilizes available resources in ascending order of costs. We should bring on stream low cost resources first and higher cost resources only as the necessity dictates. But let us assume that we have identified the various high cost sources of petroleum available to the country through studies such as this one. Nevertheless, the necessity of bringing them on stream is a function of overall objectives. For example, if the goal is self-sufficiency in petroleum supply, then all alternatives should be pursued as fast as is technically possible. The somewhat less stringent goal of 'self reliance', which among other things involves imports less than or equal to onethird of our requirements by 1985 "...recognizes, however, that the policies we will adopt have costs as well as benefits and a balance that provides the maximum advantage to Canadians must be found."[3] The self-reliance objective allows a little more flexibility in putting off high cost development to some future time. This seems rational since future conditions of demand and supply may provide better justification for developing these presently high cost sources. Furthermore, technological advances may reduce the real resource cost of developing these alternative sources.

7.3.2 Some Non Quantifiable Social Benefits of Enhanced Oil Recovery

Not all benefits and costs of economic activity can be expressed in dollar terms. Potentially adverse impacts of large projects on the environment or on some other aspect of the quality of life are difficult to evaluate because there are no well defined markets to provide information on the value to society of changes in this 'quality'. This has not overly concerned us here since we are dealing with small projects with apparently little likelihood of impairing the quality of life.

On the other hand there are a number of potential benefits which cannot be accounted for within the standard framework of individual project analysis. Such benefits, discussed below, should somehow enter into social decision making, though the precise basis on which this is done is likely to be more political than economic.

Security of supply

Although the security of supply argument may be overemphasized in current debate, the problem does exist and must be addressed at some level. Extended interruption of offshore oil supplies would have a depressing effect on the economy of North America, and Canada's relatively favourable resource situation would not exempt her. Accepting this possibility increases the importance of any activity that could serve to ameliorate it. On a more general level, declining petroleum supplies are certain to cause some adjustment problems in future. It may be that the most important contribution of enhanced recovery activities will be to reduce the impact during the transition period, until energy demands accommodate the new reality or alternative sources of energy are developed.

Rationalized planning

A related benefit to society from developing expertise in this area lies in rationalizing the planning process. Say, for example, we develop our collective skills enough to be very confident of predicting enhanced recovery potential. Then even if the actual prediction was that the potential was negligible, there would be a significant benefit to society in the form of released research resources directed at more promising alternatives. The earlier this knowledge is made available, the better our future planning will be.

Increased recoverability

Any firm engaged in an on-going search for oil could realize substantial benefits from even modest increases in recoverability by enhanced techniques since these would increase potential revenue from all future developments and discoveries. But such future benefits are often discounted by private companies at rates much greater than would be socially desirable thus reducing their attractiveness in present value terms. Furthermore, individual firms cannot be sure of capturing the benefits from tomorrow's application of processes developed today because of limited tenure arrangements and political uncertainties. So they cannot be expected to accept the full costs of developing those processes. This is not a problem from society's viewpoint, however, since either the group accepting the costs will reap the benefits or their 'heirs' will.

Again, adopting a broader viewpoint, worldwide oil recovery productivity will be significantly affected with benefits that cannot be entirely appropriated by individuals. A part of them can since technical expertise is an exportable commodity. Another part will, however, undoubtedly flow freely to the world community, ameliorating the impact of declining supplies on a world scale, and making some contribution to world stability in a difficult period.

The serendipity value of basic research

Scientific research in any area always holds the possibility of chance applications in other areas. In the present context, general benefits will accrue from geological and geophysical advances and from increased understanding of fluid flow through porous media. The serendipity value is augmented by certain 'likely' applications of this increased knowledge in related areas, such as the development of geothermal and oil sands energy sources.

7.3.3 The Role of Government

The non-competitive nature of oil producing activities and the existence of non-market benefits related to enhanced oil recovery provides some justification for government intervention. The nature and extent of that intervention is a policy decision that must be made within the constraining context of overall national objectives. Provision of a special environment to facilitate enhanced recovery activity is unwise without considering other energy supply options, a task well beyond our present scope. The notion of an 'Energy Policy' is itself potentially misleading since, to reduce a complex argument to its essentials, 'all of our problems are interdependent'.[4]

However, certain accepted regulatory activities of government are complementary to the objectives of industry and are of particular importance to enhanced recovery. First, the fact that the state of the art is relatively undeveloped means that individoal operators may be unaware of potentially profitable applications of tertiary techniques. As pools reach their producing economic limit they may be plugged and abandoned through ignorance rather than necessity. This would severely increase the costs of any later field development. Such occurrences may be prevented by the regulatory review agencies in each province that monitor development practices.

These same agencies and divisions of the federal Department of Energy, Mines and Resources and the National Energy Board provide an important service in the maintenance and update of geological, geo[illegible]sical and reservoir data. Canada is at the forefront in this area, thanks in part to observance of early errors in the U.S., and should continue to upgrade the amount and quality of this information which ultimately ends up in the public domain.

The requirement for field pilot testing offers potential for government involvement which could usefully complement industry. Although field pilot costs are a very small component of any project that reaches the development stage, they are not insignificant when it is recognized that they relate to the highest risk phase of any recovery project. A fairly modest government involvement in many projects at this initial stage would in effect pool some of the risk while reducing risk dramatically to individual operators. This would appear to be a natural activity for our national petroleum company (Petro-Canada) and one which should be welcomed by industry. The importance of such participation is increased by the fact that there are often opportunities to expand pilot tests beyond the narrow interest of an individual operator in order to obtain information of wider applicability that would help in problems of other reservoirs.[5]

General benefits from increased information dissemination might be increased significantly by a centralized agency of government. Industry does an admirable job, through related professional organizations and journals, of communicating technical developments. But there is inevitably a lag that may extend to several years in getting this information to the people who can use it most. Any action to reduce the time lag could have very beneficial results. Individual companies have little incentive to share information but a government actively sharing risks would have an interest (and much of the capability already in place) to ensure new knowledge was passed on as quickly as possible.

Governments also have the potential to directly affect the profitability of resource development through pricing, tax, and royalty policies. The range of numerical estimates emerging from the sensitivity runs of our model clearly indicate the very great impact such policies may have on the potential for enhanced recovery. The complexity of the issues is quite high, especially when we recall our earlier caveat regarding the need to integrate policy decisions in diverse areas of which 'energy supply' is only one. With this warning restated, however, we proceed to a consideration of the more important areas of concern. These involve determining the appropriate price for petroleum resources and determining appropriate tax and royalty policies to be applied to petroleum development. Decisions in these areas ultimately determine how the benefits from enhanced oil recovery will be distributed among Canadians, a somewhat controversial question with which we will conclude our discussion.

Aspects of tax policy

Controversy surrounding taxation of petroleum finding and development activities dates at least from the Carter Commission on Taxation (1966) and has centred on the depletion allowance and certain other provisions that have no counterpart in the manufacturing sector.[6] The supporters of these provisions cite special conditions in the industry; the particular difficulty of attracting international capital and the special risks associated with oil and gas finding and development activities.

The special needs for financing in the oil industry have led to suggestions that industry cash flows must be relied on to provide much of the necessary capital for finding and developing future petroleum supplies. This, in turn, leads to arguments suggesting that industry needs either more favourable tax treatment or prices approaching world levels to finance increasingly expensive exploration and development activities. This is not a particularly convincing argument since it ignores other potential sources of finance. A major function of capital markets, both domestic and international, is to facilitate project financing, and these markets appear to be responding to the need for new financing vehicles.[7] Furthermore, there is no reason why government cannot channel a good proportion of royalties and taxes back into petroleum development; solving the financing problem without giving the wealth directly to industry (which is largely foreign owned).

The second argument supporting special tax provisions for the oil industry is based on the risk associated with exploration and development. However, dry hole risks are easily pooled within large firms and risks associated with demand and supply are ameliorated by diversification and perhaps some risk sharing with customers through long term contracts. These devices are not as available to small firms who may face generally higher risks. However, it is quite probably the case that smaller firms in other industries face greater risks than large firms as well. Thus, there is a general presumption that risks in the petroleum industry have not been shown to be greater than in other industries.[8]

The activity of enhanced oil recovery may be somewhat different, however, since pooling of the risks of failure of pilot projects is less easily handled even within very large companies. Nonetheless, the results of our tax estimation suggest that for most of the potentially recoverable oil the current tax and royalty regulations actually allow industry some profit in excess of their required rate of return, assumed here to be 8 percent in real terms (15 percent in nominal terms, assuming a 7 percent rate of inflation). It appears that special tax concessions to encourage enhanced recovery should not be necessary. Government involvement may be more appropriate in areas designed to identify the true nature of associated risk elements.[9]

On a more specific level, as mentioned above, our cost analysis indicated that the most significant component of costs relates to materials rather than capital equipment. Current tax regulations allowing expensing of materials costs rather than capitalization appear appropriate for large operators with abundant income against which such expenses can be written off. Smaller operators might find capitalization of these expenses more advantageous since they could then be included in a pool such as that for Canadian Development expense which would allow them to be carried forward indefinitely. This option would provide more equal treatment of small operators vis a vis major oil companies.

There is, in fact, quite probably a general bias in the regulatory-tax environment that works in favour of the larger operators. Such a bias involves such things as income limitations on deductions that operate in favour of companies with larger taxable incomes and time limits on the carry-back and carry-forward of losses which are likely to increase risk for smaller firms that may be unable to completely use the loss provision. Such provisions generally do not affect a large company wherein losses from individual projects are likely to be completely deductible under present rules. Thus, for small companies, the incomplete loss-offset related to new projects introduces an anti-risk-taking bias to the tax system.[10] For large companies the loss-offset is complete and no bias exists. This situation may militate against enhanced recovery activities in fields controlled by smaller Canadian companies.

Tax deduction pools that can be carried forward indefinitely and passed on to new owners have the somewhat perverse effect of making it on occasion more profitable for a company to invest surplus earnings by buying another company than by engaging in the development or exploration activities for which the deductions were intended. The occasionally observed diversity of offers per share in attempted takeovers are graphic evidence of this point. Small divergencies can be accounted for by differing estimates of the worth of a company's assets but the very large differences in bids are commonly based on the relative tax positions of the bidding companies. The extent and importance of such impacts of the tax system deserve in depth study.

Royalties

Royalties are a return to the owners of the resource for allowing development and are generally claims on gross revenues rather than profits. In some instances certain cost elements may be deducted before calculation of the royalty. This is the case for enhanced recovery operations wherein any costs in excess of those deemed necessary for primary and secondary recovery may be deducted before calculation of the royalty. Although this means the royalty is not precisely levied against total revenues neither is it levied only against profits. The result is that royalties may exist, in certain cases, even when the project would otherwise just cover real development costs. Thus they may prevent development of some reservoirs that would otherwise be viable. It is arguable that royalties should be based on profits not gross revenues. This is because economic costs include the required return to capital and risk taking. Thus, when revenues from a project are just sufficient to cover economic costs, profit is zero but the project is viable nonetheless. If royalties are based on profit, all such projects will generate zero royalties and will therefore be undertaken. If royalties are based, even in part, on gross revenues all such projects will generate positive royalties and will therefore not be undertaken.

The importance of this distinction depends on whether the rights to the royalty payment reside with the public or with a private resource owner. A private owner, arguing that his claim to a return is as valid as that of the capital owner will refuse to allow development unless he receives some return (in the form of a royalty payment). In the zero profit case mentioned above, this decision would prevent development, and the consumption benefits would be lost to the public. A public owner (government) facing the same situation should forego the royalty on production to ensure that the consumption benefits from the oil provided by the project are made available to the public. The implication of this argument is that royalties should be levied on net profits only so that in case of a conflict between the owners of the resource and the owners of the capital required to develop it, the latter will prevail and the oil will be made available to consumers.

Oil price policy

Optimal pricing policies could easily be allocated a chapter (or a book) of their own. They involve difficult theoretical considerations that go beyond the level of discussion here. The purpose of this section is to provide some appreciation for our reticence to endorse recommendations for a rapid movement of domestic prices to world levels, in spite of the obvious incentive to enhanced recovery such action would entail. The position adopted here essentially recognizes a potential tradeoff between efficiency and maintenance of some potential for a strategic response to OPEC.

The orthodox economic rationale for allowing the domestic price of a depleting resource such as oil to rise to world levels has a number of elements.

1. It is presumed that higher prices will reduce consumption of oil products because of
    - a) a general reduction in purchasing power, and
    - b) greater utilization of alternative sources of energy such as natural gas, coal, and electricity.
2. It is presumed that higher oil prices will increase the supply of oil through
    - a) increased exploration activity in both interior and frontier areas, and
    - b) increased recovery from existing reservoirs by application of the somewhat more costly enhanced recovery techniques.

The first point, relating to the conservation effect of higher oil prices, is intuitively plausible in a qualitative sense but its quantitative importance is difficult to evaluate without knowledge of the responsiveness of the demand for oil to changes in its price (the price effect) and the responsiveness of the demand for oil to changes in real income (the income effect).

The price effect depends, in part, on the quantity and cost of the alternatives available to consumers. Actual substitution of other energy sources for oil increases the demand and thus the price of those sources partially offsetting their impact in reducing oil consumption. The effect of increased oil prices on purchasing power varies according to the proportion of individual consumer's incomes and wealth that comes from equity shares in the oil supply industries. The higher is this proportion, the smaller is the impact, and in fact consumers with extensive income from this source will realize an increase in purchasing power as oil prices rise which might lead them to actually increase their use of oil. It is likely that the net effect of increased oil prices would be to reduce average real incomes but to what extent this would reduce oil consumption is difficult to determine in the absence of information about income elasticities. For these reasons, the impact of increased domestic prices may be more a distributional impact and less an impact on aggregate consumption than is commonly supposed. The impact on the distribution of income will be discussed below. The consumption impact, though perhaps smaller than commonly believed, is probably significant, especially over the long term, as evidenced by the 'economy car' economies of Europe and Japan. Here again, however, more information would be required for a definitive judgment since there are other factors (besides differing levels of oil prices) that may explain differences between these economies and that of Canada.

The incentive effect of higher prices on enhanced recovery activity (and by analogy, exploration) is illustrated in the present study, wherein a significant portion of the increased monetary benefits are left with the producing companies. There is, however, an offsetting factor that has not been explicitly dealt with and which could be important in the short term future. Economists have labelled this factor 'user cost,' defined as the present value of future profit foregone by developing a resource (or using a piece of capital) today. That is, a barrel of oil produced today implies a lost opportunity to produce it (and earn a profit from it) tomorrow.

Whenever the present value of future profits is larger than present profits, user costs are positive and production may profitably be postponed to the future. This would occur, for example, if future development costs were the same as present ones but future prices of oil were higher than present prices. Postponing production to the future would reduce supplies today and cause increases in price that would raise current profits until they exceeded the present value of future profits. This would precipitate current production with a consequent depressing effect on price. Eventually, efficient production over time would yield current production levels that equated current profit with the present value of future profit foregone. Thus if future prices and costs were known with certainty, free market prices would provide an efficient guide to production over time.

However, the future is not known so we must deal only with expectations. Expectations are sometimes fragile constructs, built on weak foundations and abandoned at the slightest tremor as evidenced by wild fluctuations in the world gold market in late 1979. In other cases they are held rigidly and have a significant influence on economic activity. Giant discoveries in East Texas in the 1930s led to widespread expectations of negative user costs which caused severe overproduction, fulfilling the expectations by forcing prices down relative to costs. Government enforced prorationing and the Connally Hot Oil Act were required to alter expectations and stabilize the industry.[11] Expectations in late 1979 appear to be solidly biased toward the inevitability of higher oil prices. The collective acceptance of OPEC's monopolistic dictates through inaction on the part of consuming countries (and the tacit support of non-OPEC producers who are almost de facto members of OPEC) could lead to no other general set of expectations.

The importance of these considerations to enhanced oil recovery is this. In spite of the clear profitability of numerous projects at current prices many of these projects could be delayed by operators who expect rapid increases in price in future. Expected real price increases in excess of the real rate of interest would be sufficient to delay production since invested returns from current production would yield less than future production. Thus it should be no great surprise, given current expectations, to find a level of enhanced oil recovery activity somewhat below that indicated by current profit measures.

The situation is exacerbated in an oligopolistic industry dominated by a relatively small number of well financed firms. Such firms have considerable scope for holding off production development over time either as a response to perceived user costs or as a bargaining manoeuvre.

The problem highlights the importance to government policy makers of monitoring the real costs of different projects and energy sources in order to recognize any unrealistic demands of industry for higher prices or tax concessions. From the present analysis it appears unlikely that such concessions are required nor would they be likely to elicit any massive speed-up in the rate of current exploitation. Industry can only handle so much expansion over limited time periods. Moreover, in the absence of finely tuned royalties and taxes on differential rents, higher prices for oil, while increasing returns on new higher cost projects, will also make returns on low cost conventional fields even more attractive, so that the relative attractiveness of pushing on to new energy sources and exotic production methods will not be especially increased.

The Distribution of Benefits

We began our discussion of policy implications with the comment that in Canada the energy crisis is more a crisis of cost than supply. This applies to the global situation as well, although some countries with no indigenous supplies are more vulnerable than others. Nonetheless, the world problem is not ascribable to imminent shortages of energy but rather is due to conflicting claims on the benefits generated by energy use.[12] This conflict is usually characterized as OPEC versus the rest of the world, but the aquiescence of non-OPEC producers to OPEC policy initiatives means it would be more correctly characterized as owners of property rights to energy resources versus energy consumers.

In Canada this has precipitated an east-west debate with regard to the advisability of raising domestic oil prices to world levels. Consuming provinces argue this would seriously impair the country's competitive position in activities that are relatively energy intensive. They argue further, that the increased transfer of wealth to producing provinces would be unfair and some more equitable division of benefits should be sought. Producing provinces argue that increased energy costs would affect only a small proportion of industrial activity and that the benefits of oil development rightfully belong to them just as benefits from other resources belong to the provinces in which they are found.

There is no simple solution to this debate. There are some strong economic arguments, discussed in the previous section, in favour of moving domestic oil prices to world levels. These include promoting conservation, accelerating domestic exploration and enhanced recovery, encouraging the development of other energy sources, and increasing the likelihood of end users choosing already available alternatives. Adverse impacts on individual industries would be better handled by direct subsidies than by holding prices down for all users. Each time we use a barrel of oil domestically and assign it a lower value than we could have received by exporting it we have incurred a net loss.

The essentials of this argument have been presented by several authors usually in discussion of the export tax and subsidy arrangements.[13] An oil export tax combined with a subsidy on the price of imported oil results in a transfer of benefits from owners and producers of oil to consumers. But there are also deadweight losses, losses that are not offset by gains elsewhere in the economy. It is these losses upon which arguments against interfering with world prices are, in part, based. Further arguments against domestic prices lower than world levels relate to the incidence of the subsidy.

Low domestic prices benefit all consumers, rich and poor alike, although there is some evidence that the subsidy is progressive and thus benefits the poor more than the rich.[14] But also among the beneficiaries are manufacturing industries that, because of reduced fuel costs, realize increased profits a portion of which go to foreign shareholders. Similarly, export industries may translate reduced fuel costs into reduced prices, which benefits them due to increased penetration of foreign markets but also may benefit foreign consumers through reduced prices.

Professor T. L. Powrie has investigated the effect of including gains and losses to foreigners in the analysis and has concluded that under a reasonable set of assumptions the deadweight losses caused by the export tax may be more than offset by an induced transfer of benefits from foreign shareholders to domestic beneficiaries.[15] This is a useful restriction on the generality of the orthodox analysis which also points up the complexity of the problem. Nonetheless, Professor Powrie recognizes a better approach than the export tax to maximize national income, namely higher rates of either profit related royalties or corporate income taxes. If either or both these instruments are feasible he would support prices approaching world levels.

The efficiency arguments in favour of a single price for Canadian domestic oil at the world level are compelling and widely accepted among economists. On the other hand, it is difficult to ignore the fact that the world price is clearly monopolistic, contrived by a cartel rather than by freely operating forces of demand and supply. The implications of this are not entirely clear because the theoretical optimum rate of change of prices for a depleting resource cannot be determined without knowledge of future levels of demand and supply. This means we cannot say in certainty whether current price levels (and rates of depletion) are above or below the optimum level. The existence of spot prices for oil (in late 1979) that are in excess of twice the average OPEC price may suggest the average price is still below some long run optimum. However, these spot prices are, in fact, due to the supply restriction imposed by the producers and it does not appear unreasonable to assume that the effect of the cartel accords with predictions of economic theory in reducing production and increasing prices to a level above the long term optimum.[16] Such monopolistic exploitation is recognized in theory as increasing benefits to producers at the expense of consumers usually with the undesirable result of reducing combined benefits from what they would be in a competitive situation. For this reason monopolies are banned by law or at least closely regulated in most if not all countries. The acceptance of such a price as a 'justifiable' benchmark appears somewhat tenuous.

The above discussion suggests that the world oil price is probably supported at artificially high levels by the monopoly power of OPEC. The Canadian domestic price, often referred to as 'artificially low', may in fact be closer to a socially optimum price than the world price. But the fact that Canada is small relative to the world oil market compels acceptance of this price as the opportunity cost of domestically consumed oil. A possible objection to this passive view is that it precludes consideration of potential countermeasures, such as a 'consumer cartel' or the use of strategic materials in trade to attempt to reduce the power of one group of countries to unilaterally set the price of such a vital commodity, and in so doing to funnel an increasing fraction of the world's wealth into their treasuries. Furthermore, there is some danger that acceptance of a contrived world price may provide an artificial incentive causing excessive investment in high cost sources. If the cooperating producers break up or decide that they have exceeded the optimal price from their own point of view, subsequent price reductions could make such investment uneconomic.

But Canada is small and acting alone can have little impact on the world market. So if we reject the possibility of a collective response to OPEC, the received wisdom about domestic prices does not seem unreasonable. The theoretical optimization of total benefits to Canadians would occur by allowing petroleum prices to rise to the level of the best alternative, currently imported oil. This is true regardless of how the world price is set since in any case it represents the opportunity price as far as Canada is concerned. The resulting benefits then should be distributed in some fashion among those who have a claim to them. Such a distribution is a sensitive issue since claimants include at least two levels of government, producers and consumers.

Over the longer term it might be more appropriate to adopt as a target some price that approximates the marginal cost of energy supplies including those from non-petroleum sources. The actual cost will depend on the level of energy supplies that it is decided to provide from domestic sources. A political decision to pursue self sufficiency in energy, though it should be taken with some knowledge of the costs involved, would determine the level of domestic energy supplies required and thus determine the incremental costs required to achieve it. The costs might be above or below the world petroleum price. Such a decision would require a degree of commitment so that possible subsequent reductions in import costs would not be allowed to interfere with investments in developing domestic sources but would rather be accepted as part of the cost of the security of self sufficiency. This scenario would increase the importance of enhanced recovery from conventional reservoirs since our cost estimates appear favourable when compared with costs of many alternative sources of energy.

Whatever the persuasion of the debaters there seems to be general agreement that if domestic prices are to move to world levels they should do so gradually. This would minimize general adjustment costs in the economy which are thought to be higher for more rapid changes. Our discussion of user costs contributes another reason for gradual price increases. If the rate of increase in prices is expected to exceed the rate of interest, there is a definite and rational incentive for producers to slow down production and delay bringing new projects on stream. They can earn more by leaving the oil in the ground to appreciate in value. To avoid downward pressure on domestic supplies, either direct regulation is required or the rate of price increase adopted should be less than the rate of interest (a proxy for alternative investment opportunities).

This discussion exemplifies the difficulties in even attaining the proper perspective from which policy suggestions related to Enhanced Oil Recovery should be viewed. World prices would provide a prime development incentive, yet their overall effect on the country's welfare (which must be the ultimate concern of government) is not unambiguous.

Footnotes

[1] Lewin and Associates, Inc., The Potential and Economics of Enhanced Oil Recovery (Washington, D.C.), prepared for Federal Energy Administration, April 1976.

[2] Glenn P. Jenkins, Capital in Canada: Its Social and Private Performance 1965-1974 (Ottawa: Economic Council of Canada), October 1977, Discussion Paper No. 98.

[3] Canada, Department of Energy, Mines and Resources, An Energy Strategy for Canada: Policies for Self Reliance (Ottawa: Department of Energy, Mines and Resources, 1976), p. 124.

[4] An illuminating brief discussion of this point is provided by Professor Kenneth G. Boulding in "Energy Policy: A Piece of Cake," Technology Review, December, 1977, p. 8.

[5] National Petroleum Council, Enhanced Oil Recovery, EOR: An Analysis of the Potential for Enhanced Oil Recovery from Known Fields in the United States 1976-2000, H. J. Haynes, Chairman, Committee on Enhanced Recovery Techniques (Washington, D.C.: National Petroleum Council, 1976), p.3.

[6] The Royal Commission on Taxation, known as the Carter Commission, recommended the abolition of 'inefficient concessions to industry' among which was the depletion allowance. This recommendation was not adopted. Canada, Royal Commission on Taxation, Press Releases, 1966, pp. 1-3.

[7] R. J. Jennings, "Specialized Methods of Financing for the Canadian Petroleum Industry" Paper No. 79-30-33; Ian H. MacKay, "Energy Financing International" Paper No. 79-30-34; G. R. Castle, "Project Financing Alternatives" Paper No. 79-30-32. Papers presented at the 30th Annual Technical Meeting of the Petroleum Society of CIM, Banff, Alberta, May 8-11, 1979. Terry R. Gibson, Peter L. Jones, and Michael J. Tims, "A Survey of Financing Alternatives," Oilweek, October 22, 1979, pp. F2-F8.

[8] Joseph E. Stiglitz, "The Efficiency of Market Prices in Long-run Allocations in the Oil Industry," in Studies in Energy Tax Policy, ed. Gerard M. Brannon (Cambridge, Mass.: Ballinger, 1975), ch. 3.

[9] It is worth noting that current tax regulations by allowing deduction of capital costs in return for a share of the profit reduces risk below what it would otherwise be and may therefore increase risk taking activities. See Stiglitz, p. 77.

[10] R. M. Hyndman and M. W. Bucovetsky, "Rents, Rentiers, and Royalties: Government Revenue from Canadian Oil and Gas," in The Energy Question: An International Failure of Policy, vol. 2, ed. Edward W. Erickson and Leonard Waverman (Toronto: University of Toronto Press, 1974), p. 199.

[11] The example is due to Paul Davidson, "The Economics of Natural Resources," Challenge, March/April 1979, p. 43. Professor Davidson is one of the more voluble and articulate proponents of active policies to oppose OPEC. See also the special section on 'The Oil Price Decontrol Debate' in the July/August issue of Challenge. (Bib., White Plains, New York).

[12] Paul Davidson, "What is the Energy Crisis?" Challenge, July/August 1979, p. 41.

[13] T. L. Powrie, "Static Redistributive and Welfare Effects of an Export Tax," in Natural Resource Revenues: A Test of Federalism. ed. Anthony Scott (Vancouver: University of British Columbia Press, 1976). G. Campbell Watkins, "Canadian Oil and Gas Pricing," in Oil in the Seventies, ed. G. Campbell Watkins and Michael Walker, (Vancouver: The Fraser Institute, 1977). Leonard Waverman, "The Two Price System in Energy: Subsidies Forgotten," Canadian Public Policy, Winter 1975.

[14] Waverman, pp. 84-87.

[15] Powrie.

[16] Harold Hotelling, "The Economics of Exhaustible Resources," The Journal of Political Economy, April 1931, p. 151.

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APPENDICES

APPENDIX A

APPENDIX A

THE DATA BASE, SCREENING PROCEDURE, AND EXTRAPOLATION PROCEDURE

A.1 The Data Base and Screening Procedure

The data on original and remaining oil in place, projected primary and secondary recovery, and various reservoir characteristics are based on the ERCB reserves report for 1975, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur at December 31, 1975. The data on sandstone reservoirs were passed through a technical screening procedure developed by the Petroleum Recovery Institute (Calgary), and described in Interim Report IR-6, "Enhanced Oil Recovery Potential in Alberta Sandstone Reservoirs," May 1977.[1]

The technical screen utilized critical parameters as documented in the literature to eliminate reservoirs that were unsuitable to enhanced recovery or that were suitable in general technical terms but did not meet the criteria for any of the specific processes being investigated (Exhibit A.1). The successful candidates were allocated to those processes for which a given candidate (reservoir) met the technical requirements. Thus a given candidate could be, and often was, allocated to more than one process. The technical screen made no attempt to determine which, if any, process would be preferable in any reservoir.

EXHIBIT A.1

ENHANCED RECOVERY PROCESSES INCORPORATED IN THE PETROLEUM RECOVERY INSTITUTE'S TECHNICAL SCREEN

- Polymer
  - Mobility control
  - Diverting and blocking
- Microemulsion Flooding
- Alkaline
  - Wettability reversal
  - Emulsification and entrapment
- Carbon Dioxide (CO_2) Miscible
- Carbon Dioxide (CO_2) Immiscible
- Thermal
  - Combustion
  - Steam stimulation
  - Steam displacement

SOURCE: B. Agbi, "Enhanced Oil Recovery Potential in Alberta Sandstone Reservoirs" (Calgary, Petroleum Recovery Institute, May 1977).

A similar screening procedure was carried out for carbonate reservoirs.[2] The procedure in this case checked only whether each reservoir would be technically amenable to carbon dioxide miscible or immiscible processes. Carbonate reservoirs are much less permeable than sandstone reservoirs and it was felt[3] that only miscible or immiscible gas processes would be successful.[3] Hydrocarbon processes were neglected because at the time the screen was developed the availability and price of hydrocarbon injection materials seemed to preclude them from consideration.

At the screening stage, data limitations related primarily to reservoir parameters required for the screening procedure but not available from the ERCB data. The treatment of missing data, as described in Interim Report IR-6 was primarily to estimate them using published correlations with other reservoir parameters. In some cases missing data was simply set to the screening tolerance in order to allow the reservoir to pass through the check.

Supplementary data were required to run the models developed here. The determination of residual oil saturation after waterflood is discussed in Section 4.3. These data were manually incorporated into the data base. Similarly, the models sometimes required data on reservoir pressure and viscosity, which were not always available from the ERCB data base. In these cases correlations with other relevant characteristics were carried out by PRI and manually inserted.

Additional adjustments to the general data base were required before it could be used for this study. The polymer model developed here is suitable for simulating the polymer mobility control process but not the diverting and blocking process. We were unable to develop a satisfactory model for diverting and blocking and so eliminated it from consideration. This had little impact on the aggregate estimation of potential since the candidates eligible for diverting and blocking polymer treatment were, in most cases, also eligible for one or more other processes and were thus included eventually anyway.

The two categories of alkaline flooding were combined and evaluated by our alkaline model. Similarly, carbon dioxide miscible and immiscible processes were combined and evaluated by the CO_2 miscible model presented in Chapter 4. In addition, we incorporated a hydrocarbon miscible model which was applied to the same set of reservoirs as the carbon dioxide model. In each case economic considerations ultimately decided which of the two miscible gas processes would be used. The set of models that were used in this study are presented in Exhibit A.2.

EXHIBIT A.2

ENHANCED RECOVERY PROCESSES INCORPORATED IN THE EVALUATION OF EOR POTENTIAL

Chemical	
Polymer	(omits diverting and blocking potential)
Microemulsion	
Alkaline	(combines wettability reversal and emulsification and entrapment potential)
Miscible Gas	
Carbon dioxide (CO_2) miscible	(combines miscible and immiscible potential)
Hydrocarbon miscible	(based on reservoirs eligible for CO_2)
Thermal	
In situ (wet) combustion	
Steam drive (displacement)	
(Cyclical) Steam stimulation	

A.2 Tertiary Recovery Potential in Canada--The Extrapolation Procedure

The extrapolation procedure is conceptually straightforward but somewhat complex in its details. It is most easily understood with reference to Exhibit A.3, which outlines the calculation for Saskatchewan. The amounts reported in Exhibit A.3 were derived from various published sources described below:

1) Original oil in place (OOIP) was categorized according to oil type (heavy or light-medium) and reservoir type (carbonate or sandstone).

2) These amounts were reduced by projected ultimate recovery by primary and secondary methods to obtain ultimate remaining oil in place (ROIP). The heavy oils were reduced by 7 percent and the light-medium by 29 percent; amounts implied by the 1977 ERCB reserves report.[4] This left the estimate of ultimate remaining oil in place.

3) The next step was to determine the 'technical' target. In Alberta, the technical target was the oil that successfully passed the screening procedure. This was 68 percent of the ultimate remaining oil in place so this percentage was used to establish the technical target in other areas of the country.

4) The technical target was then classified by the enhanced recovery process group (thermal, chemical or miscible) likely to apply. In the case of heavy oils the applicable group was thermal. For the light-medium oils in carbonate reservoirs the applicable group (in this study) is miscible gas. For the light-medium group contained in sandstone reservoirs chemical

EXHIBIT A.3

EXTRAPOLATION PROCEDURE AND RESULTS FOR SASKATCHEWAN

Saskatchewan OOIP (Mstb)

10,542,149

	Heavy < 25° API	Light-medium > 25° API 5,404,055		
1)	sandstone 5,138,094 -7% (359,667)	sandstone 595,545 -29% (172,708)		carbonate 4,808,510 -29% (1,394,468)
2) Ultimate ROIP:	4,778,427	422,837		3,414,042
3) Technical target (68%):	3,249,330	287,529		2,321,549
		10% 28,753	90% 258,776	
4) Recovery method:	thermal	chemical	miscible	miscible
5) Reduction by recovery factors:	38.8% 1,260,740	17.6% 5,061	15.4% 39,852	19.9% 461,988
6) Reduction by profitability factors:	82.8% 1,043,893	48.4% 2,449	87.7% 34,950	70.2% 324,316

Total economically recoverable oil for Saskatchewan: 1,405,608 Mstb.

processes account for 10 percent and miscible processes for 90 percent of the dominant (economically preferable) oil recovery methods. These were the actual percentages from the Alberta simulation.

5) At this stage we assumed that the same percentage of the technical target that was recovered in the simulated Alberta case would be recovered in all other areas. The average recovery factors by process group that emerged from the Alberta simulations are as follows:

Thermal	0.388
Chemical	0.176
Miscible (sandstone)	0.154
Miscible (carbonate)	0.199

These factors were applied to the technical target for each process group to determine the amount of oil that was 'technically recoverable'.

6) The procedure to this point provided us with an estimate of 'technically recoverable' oil for each process group. The final step was to reduce this amount to the 'economically recoverable' amount under our assumptions of a $20 per barrel oil price and an 8 percent (real) discount rate. To do this the ratio of oil recoverable from profitable pools (under current tax and royalty regulations) to the technically possible recovery in each process group was established (Table A.1). These 'profitable pool factors' were then applied to the 'technically recoverable' oil (from step 5) to determine our estimate of economic enhanced oil recovery.

TABLE A.1

PROFITABLE POOL FACTORS BASED ON INCREMENTAL RECOVERY
AT 8 PERCENT DISCOUNT RATE AND PRICE OF $20
(percent)

Process Group	Profitable Incremental Recovery DR=8%, P=$20 (MMbbl)	Technically Possible Incremental Recovery (MMbbl)	Profitable Oil as a Percentage of Technically Recoverable
Chemical	115.435	238.284	48.4
Thermal	406.743	491.435	82.8
Miscible Gas			
Sandstone	1,050.465	1,198.406	87.7
Carbonate	834.136	1,187.504	70.2

The above procedure was applied to Saskatchewan, British Columbia and all other provinces and territories combined. The latter group included Manitoba, Ontario, other Eastern Canada and the territories. The procedures and results are outlined in Exhibits A.3, A.4 and A.5.

To determine the ultimate tertiary recovery potential in Canada, the estimates of OOIP, ultimate ROIP, technical tertiary target and economically recoverable oil were summed across each level in Exhibits A.3, A.4 and A.5 and added to the Alberta estimates. This result is presented in Chapter 5, Table 5.1 and Figure 5.1.

Data Sources

The data on which the calculations described above are based are presented in Table A.2 and are based on a variety of sources as identified in the table.

TABLE A.2

CRUDE OIL RESERVES IN CANADA
ORIGINAL IN PLACE AT DECEMBER 31, 1976

	Proved (Mstb)	% of Proved Total
Territories	500,000	1.01
British Columbia	1,213,818	2.46
Alberta	36,144,386	73.34
Saskatchewan	10,542,149	21.39
Manitoba	670,634	1.36
Ontario	193,196	0.39
Other Eastern Canada	18,000	0.04
Total Canada	49,282,183	100.00[a]

SOURCE: Canadian Petroleum Association, Statistical Handbook, 1978, Section II, Tables 17, 17A.
The Alberta, Saskatchewan and British Columbia provincial proved totals are from Alberta Energy Resources Conservation Board, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur (at December 31, 1976), Report 77-18; Saskatchewan Government, 1976 Petroleum and Natural Gas Reservoir Annual, 1977; British Columbia Government, Hydrocarbon and By-Product Reserves in British Columbia (at December 31, 1976), 1977.

[a] May not add to 100 due to rounding.

EXHIBIT A.4

EXTRAPOLATION PROCEDURE AND RESULTS FOR BRITISH COLUMBIA

British Columbia OOIP (Mstb)

1,363,642

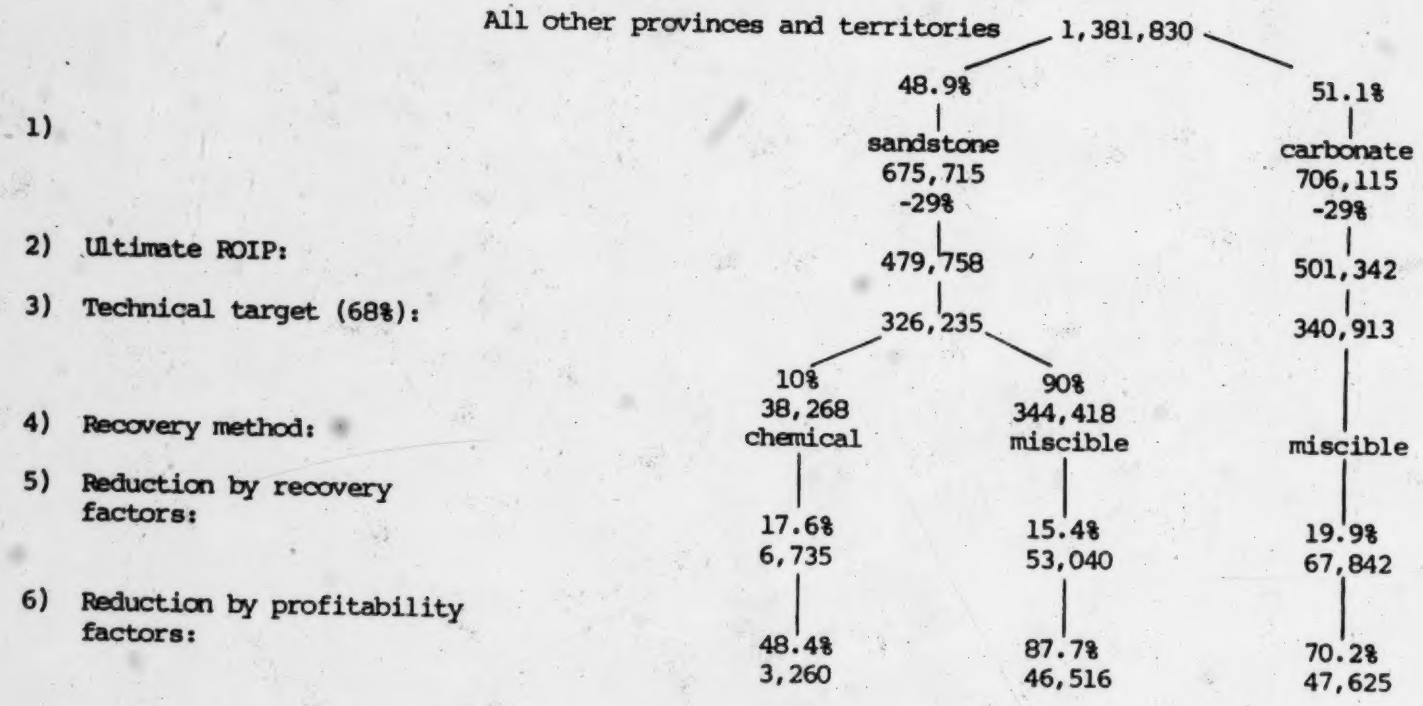
1)		sandstone 792,640 -29%		carbonate 571,002 -29%
2)	Ultimate ROIP:	562,774		405,411
3)	Technical target (68%):	382,686		275,680
		10% 38,268	90% 344,418	
4)	Recovery method:	chemical	miscible	miscible
5)	Reduction by recovery factors:	17.6% 6,735	15.4% 53,040	19.9% 54,860
6)	Reduction by profitability factors:	48.4% 3,260	87.7% 46,516	70.2% 38,512

Total economically recoverable oil for British Columbia: 88,288 Mstb.

EXHIBIT A.5

EXTRAPOLATION PROCEDURE AND RESULTS FOR ALL OTHER PROVINCES AND TERRITORIES

Territories OOIP (Mstb)	500,000
Manitoba OOIP (Mstb)	670,634
Ontario OOIP (Mstb)	193,196
Other Eastern Canada OOIP (Mstb)	18,000



Total economically recoverable oil for all other provinces and territories: 97,401 Mstb

The Saskatchewan Petroleum and Natural Gas Reservoir Annual uses six categories to classify crude oil according to its API gravity. Areas I and II Heavy indicated that all OOIP contained in these categories fell in the less than 25° API range. Area III Medium contained only 98.19 percent OOIP less than 25° API. The 1.81 percent (39,196 Mstb) of OOIP in Area III Medium that did have API gravity greater than 25° was included as heavy oil in this study. This agrees with the National Energy Board classification. However, the NEB classifies the Midale-Weyburn producing horizon of Area IV Medium as heavy oil even though the API gravity of the oil is 28° API. For simplification this oil was considered to fall in the light crude oil range so that heavy oil comprised Areas I and II Heavy and Area III Medium and the three remaining areas are considered to be light crude oil. The classification of Saskatchewan oil by rock type and by oil type is presented in Table A.3.

TABLE A.3

ORIGINAL OIL IN PLACE IN SASKATCHEWAN
BY RESERVOIR ROCK TYPE

Provincial Area Classification		Original Oil in Place by Reservoir Rock Type (Mstb)		
		Sandstone	Carbonate	Total
Area I	Heavy	2,457,069	0	2,457,069
Area II	Heavy	515,415	103	515,518
Area II	Light	555,890	0	555,890
Area III	Medium	1,135,009	1,030,498	2,165,507
Area IV	Medium	19,436	2,446,674	2,466,110
Area IV	Light	20,219	2,361,836	2,382,055
Total		4,703,038	5,839,111	10,542,149
% of Provincial Total		44.6	55.4	100.0

SOURCE: Saskatchewan Government, 1976 Petroleum and Natural Gas Reservoir Annual, 1977, Table C.

In the case of British Columbia and the 'all other' category the procedure for light-medium was used since no heavy oil was reported in these areas. The OOIP division between sandstone and carbonate reservoirs for British Columbia was calculated by totaling the OOIP in carbonate pools reported in the Engineering and Geological reference book, Oil and Gas Pools in British Columbia. This amounted to 571,002.2 Mstb of OOIP in carbonate pools for British Columbia. To determine the OOIP in carbonate reservoirs for the all other provinces and territories category, the total carbonate OOIP for British Columbia, Alberta and Saskatchewan was extrapolated to total Canada since these provinces account for 97 percent of the total OOIP for Canada. The amount of Alberta carbonate OOIP was calculated by taking 47 percent of the total Alberta OOIP. This percentage was reported in F. McCaffery, et al, "A Treatise on Hydrocarbon Recovery from Carbonate Reservoirs." The ratio of OOIP in carbonate reservoirs for British Columbia, Alberta, and Saskatchewan to total OOIP for the three provinces was then applied to the total OOIP in all other provinces and territories to determine the OOIP in carbonate reservoirs for this category (Table A.4). This resulted in a percentage of 48.8 percent OOIP found in carbonate reservoirs in Canada. This percentage was applied to the all other provinces and territories category to divide the OOIP according to its occurrence in sandstone or carbonate reservoirs.

TABLE A.4

ORIGINAL OIL IN PLACE IN CANADA FOUND IN CARBONATE RESERVOIRS AS OF DECEMBER 31, 1976

	Original Oil in Place (Mstb)	OOIP in Carbonate Reservoirs (Mstb)	% of OOIP in Carbonate Reservoirs (%)
British Columbia	1,213,818	571,002	47.0
Alberta	36,144,386	16,987,861	47.0
Saskatchewan	10,542,149	5,839,111	55.4
Total	47,900,353	23,397,974	48.8

Total Canada: 49,282,183, therefore British Columbia, Alberta and Saskatchewan account for 97.2 percent of Canada's OOIP.

SOURCE: 1) Table A.3
2) British Columbia Government, Engineering and Geological Reference Book, Oil and Gas Pools in British Columbia, 1977.
3) F. G. McCaffery, et al., "A Treatise on Hydrocarbon Recovery from Carbonate Reservoirs," 1978.

A.2.1 Calculation of Study Producibility Forecast

The study estimates of additions to the producibility forecast for Canada, from enhanced oil recovery, were calculated using the base case computer simulation and the National Energy Board base case producibility scenario. The reserves additions owing to tertiary recovery and infill drilling were subtracted from the NEB base case before adding on the study estimate to avoid duplication in the tertiary producibility estimate.

The NEB producibility scenarios are tabulated in appendices in the September 1978 Board report, Canadian Oil Supply and Requirements. Daily production rates per year are given for the period 1978-1995. The production rates are divided between light and heavy crude oil equivalent and are further disaggregated to show the future production increment from reserves additions. Reserves additions include conventional recovery from undeveloped pools, new discoveries, infill drilling, waterflooding, and additions from improved recovery. The percentage of additions that are due to improved recovery and infill drilling were calculated from Tables 2-5 and 2-8 in the NEB report (Table A.5). These percentages were then applied to the reserves additions columns recorded by the NEB to obtain the reserves additions amounts from improved recovery. This was then subtracted from the total crude oil and equivalent to give a base case producibility estimate excluding tertiary and infill drilling. This procedure is presented explicitly in Table A.6. The result was a column of projected production figures which is the NEB base case with their estimate of tertiary production and infill drilling production removed. We wanted these figures in order to develop our own Canadian producibility forecast by adding our estimate of tertiary production to the NEB estimate of production from all sources except tertiary production and infill drilling.[5]

The study producibility forecast was calculated using our Alberta base case yearly production forecast. The percentages of total production that occur in each year were calculated. These year by year percentages were then applied to the extrapolated value of 4.0 billion barrels of incremental recovery for Canada. The result of this for the 28 year period was then converted to thousands of barrels per day. The daily production figures were then added to the NEB base case forecast starting in 1980 (after subtracting their estimate of tertiary and infill drilling). The NEB base case estimate was extrapolated to remain at 1,121 Mb/d after 1985. This procedure is detailed in Table A.7.

The study estimate in conjunction with the NEB base case estimate graphically portrayed is a curve with a production peak of 2,178 Mb/d occurring in 1991. This curve is presented in Chapter 5, Figure 5.2.

TABLE A.5

NEB ESTIMATE OF POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM IMPROVED RECOVERY BASE CASE (millions of barrels)

	Light Crude Oil	Heavy Crude Oil
Tertiary Recovery:		
Chemical Flooding	310	25
Miscible Flooding	370	110
Thermal Techniques	30	1,445
Infill Drilling	130	35
Total Tertiary & Infill Drilling	840	1,615
Waterflooding	140	135
Undeveloped Pools	--	420
New Discoveries	--	400
Total Reserves Additions	980	2,570
Calculation of % of Reserves Additions that include Tertiary Recovery and Infill Drilling:	$\frac{840}{980}$ = 85.4%	$\frac{1,615}{2,570}$ = 62.8%

SOURCE: National Energy Board, Canadian Oil Supply and Requirements, September 1978, Tables 2-5, 2-8 and 2-9.

TABLE A.6

POTENTIAL PRODUCIBILITY OF CRUDE OIL:
NEB BASE CASE ESTIMATE EXCLUDING TERTIARY
(Mb/d)

	Light Crude Oil		Heavy Crude Oil				
	Total Reserves Additions (1)	Additions Owing to Tertiary & Infill Drilling 85.4% of (1) (2)	Total Reserves Additions (3)	Additions Owing to Tertiary & Infill Drilling 62.8% of (3) (4)	Total Crude Oil & Equivalent (5)	Tertiary & Infill Drilling (6)	NEB Base Case Minus Tertiary & Infill Drilling (5) - (6) (7)
1978	14	12	9	6	1,826	18	1,808
1979	34	29	20	13	1,809	42	1,767
1980	58	50	30	19	1,709	69	1,640
1981	83	71	40	25	1,598	96	1,502
1982	103	88	52	33	1,497	121	1,376
1983	123	105	59	37	1,413	142	1,271
1984	137	117	67	42	1,335	159	1,176
1985	151	129	76	48	1,289	177	1,112
1986	164	141	89	56	1,244	197	1,047
1987	170	146	102	64	1,245	210	1,035
1988	176	151	116	73	1,313	224	1,089
1989	178	153	127	80	1,327	233	1,094
1990	182	156	136	85	1,331	241	1,090
1991	189	162	144	90	1,339	252	1,087
1992	192	165	152	96	1,350	261	1,089
1993	195	167	157	99	1,373	266	1,107
1994	195	167	162	102	1,381	269	1,112
1995	195	167	166	104	1,392	271	1,121

SOURCE: National Energy Board, Canadian Oil Supply and Requirements, September 1978, Appendix G, p. 260.

TABLE A.7

STUDY PRODUCIBILITY FORECAST

	Alberta		Canada		NEB Base Case minus Tertiary & Infill Drilling	Canada Forecast
Year	(MMb/yr)	(%)	(MMb/yr)	(Mb/d) (1)	(Mb/d) (2)	(Mb/d) (1) + (2)
1980	2.32	0.096	3.86	11	1,640	1,651
1981	6.63	0.275	11.03	30	1,502	1,532
1982	18.40	0.765	30.58	84	1,376	1,460
1983	36.30	1.508	60.34	165	1,270	1,435
1984	62.94	2.615	104.61	287	1,170	1,457
1985	95.34	3.961	158.45	434	1,112	1,546
1986	134.31	5.581	223.23	612	1,048	1,660
1987	167.32	6.952	278.09	762	1,035	1,797
1988	196.34	8.158	326.32	894	1,089	1,983
1989	220.50	9.162	366.46	1,004	1,095	2,099
1990	235.80	9.797	391.89	1,074	1,090	2,164
1991	239.60	9.955	398.21	1,091	1,087	2,178
1992	226.16	9.397	375.87	1,030	1,090	2,120
1993	204.87	8.512	340.49	931	1,107	2,038
1994	174.69	7.258	290.33	795	1,112	1,907
1995[a]	138.12	5.739	229.56	629	1,121	1,750
1996	97.79	4.063	162.52	445	1,121	1,566
1997	67.45	2.802	112.09	307	1,121	1,428
1998	42.39	1.761	70.45	193	1,121	1,314
1999	22.37	0.930	37.18	102	1,121	1,223
2000	9.86	0.410	16.39	45	1,121	1,166
2001	3.32	0.138	5.52	15	1,121	1,136
2002	1.87	0.078	3.11	9	1,121	1,130
2003	0.98	0.041	1.63	4	1,121	1,125
2004	0.58	0.024	0.94	3	1,121	1,124
2005	0.32	0.013	0.52	1	1,121	1,122
2006	0.15	0.006	0.26	1	1,121	1,121
2007	0.06	0.002	0.09	1	1,121	1,121

[a] NEB base case extrapolated beyond 1995 to remain at 1,121 Mb/d.

[1] Our screening results are not identical to those presented in PRI's Interim Report primarily because their initial screening procedure eliminated reservoirs in the alkaline group when CO_2 or H_2S was found to be present. This constraint was eliminated at the time the screen was used for the present study.

[2] B. Agbi, *Enhanced Oil Recovery Potential in Alberta Conventional Crude Oil Reservoirs: A Technological and Economic Evaluation* (Calgary: Petroleum Recovery Institute), Forthcoming.

[3] Other processes will in practice be considered for some carbonate reservoirs but the most promising approach appears to be miscible gas.

[4] This estimate is based on ERCB Report 78-18, Table 2.6, p. 2.71. The light-medium recoverable reserves by primary and waterflood methods are 9,450 million bbls. This is 29 percent of total initial in-place reserves of 32,333 million stbs, The heavy oil primary recoverable reserves of 306 million bbls represent 6.6 percent of initial in-place reserves of 4,569 million bbls.

[5] Infill drilling, the process of drilling additional wells in a producing field in order to increase production, was excluded since it was assumed that our tertiary recovery estimate would replace this rather than augment it.

APPENDIX B

APPENDIX B

COST ESTIMATES

All costs reported in Appendix B are in 1978 dollars. With a few exceptions, all cost data were developed from various sources in the literature and revised and updated in consultation with representatives of industry. Industry cooperation was predicated on confidentiality of individual sources which precludes detailed source documentation for most of the cost tables presented here.

B.1 Capital Costs

Capital costs in the oil industry are generally divided into two major categories, exploration and development. Only the latter category is of interest in this study and it normally includes:

a) drilling and completion costs
b) injection and production equipment including flow lines, separators, tanks and lease equipment
c) steam generators, air compressors and environmental control equipment (where required)
d) lease and road construction costs
e) processing plant costs.

We have assumed that d) and e) are sunk costs for an EOR project and have developed estimates for a), b), and c) only. The estimates for item b) are estimates of incremental costs of the items required for tertiary recovery. They are presented in Table B.1.

Environmental aspects of enhanced oil recovery are discussed in Section 6.3.5. The private costs necessary to prevent environmental damage do not appear significant except in the case of the thermal processes. The costs of pollution abatement are included with the estimates for steam generators, air compressors and associated equipment discussed in Section B.3.

B.1.1 Well Drilling and Completion

Drilling and completion cost estimates are based on relationships developed by ERCB. The data from which these relationships were derived were the statutory declarations of operators that are filed

TABLE B.1

INJECTION AND PRODUCTION WELL EQUIPMENT COSTS
$/well

	Well Depth in Feet				
	0-2,500	2,500-5,000	5,000-7,500	7,500-10,000	10,000+
Production Equipment (includes lift equipment, separators, tanks and flow lines but not waterflood equipment)	15,000	37,000	42,000	50,000	70,000
Water Injection $/injector	33,500	33,500	43,000	53,000	60,000

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.

monthly with various departments of the provincial government. ERCB analyzed these data and were able to fit curves to them for three areas of the province, identified in Figure 1.2. Costs vary by area and by depth as shown in Table B.2.

TABLE B.2

WELL DRILLING AND COMPLETION COSTS
$/foot

Depth	Plains	Northern/Central	Foothills
1000	40	100	100
1 - 2	45	83	103
2 - 3	46	70	106
3 - 4	46	67	109
4 - 5	45	66	113
5 - 6	50	70	116
6 - 7	53	77	126
7 - 8	56	88	139
8 - 9	60	98	154
9 - 10	66	112	178
10 - 11	72	133	202
11 - 12	80	152	233
12 - 13	88	178	271
13 - 14	98	205	324
14 - 15	111	244	389
15 - 16	127	297	410
16 - 17	143	359	420
17+	150	393	430

SOURCE: Estimated from graphs and data provided by the Alberta Energy Resources Conservation Board.

Table B.2 is based on the curves provided by ERCB with some extrapolation at end points. The ERCB curves related exploratory drilling costs to depth in the plains, northern and central, and foothills areas of the province. Exploration and development drilling are similar activities especially when they are considered net of completion costs, the costs required to complete a well in preparation for production. Nonetheless there might be an intuitive presumption that exploratory drilling is more expensive and using it as a proxy for development drilling would bias the results in an upward direction. While this may be true, we felt that since we were basing our estimates on 1974, 1975 and 1976 data we might be wise to err on the conservative side. In any case the ultimate costs were widely accepted within industry as being representative of realized development drilling and completion costs in 1978. Since we required total costs of well development (i.e., including well completion costs) some adjustments to the ERCB relationships were required. For enhanced recovery well development it was felt that completion costs net of major road construction costs should be added to the drilling costs. Fortunately we had some basis for estimating this cost element.

Operators reported well development costs in detail and ERCB extracted all cost elements not directly related to drilling and classified them as completion costs. These were deducted from total costs to get drilling costs from which their curves were derived. We were allowed limited access to the data to allow us to estimate the required adjustment for our purposes. Examination of the data revealed that road costs accounted for approximately 10 percent of completion costs in the northern central and foothills regions but were negligible in the plains regions. These road costs would not be applicable to enhanced recovery schemes since in most cases roads would already be in place. It was decided to use the simple average of completion costs net of road costs in various depth categories to adjust the drilling costs upward for use in our model. The adjustment factors are given in Table B.14.

The initial cost data were reported monthly from 1974 to 1976 and ERCB escalated the drilling costs at a rate of 26 percent per year to December 1977. We escalated them at the same rate to 1978. To summarize, we took drilling costs by area and depth from graphs provided by ERCB, added a calculated amount for completion costs by depth category and divided the result by depth to get a cost per foot for use in the various production models. The detailed calculation by region is discussed in Section B.4. The resulting cost matrix incorporated in the model is given in Table B.2.

Limitations of the analysis

Drilling and completion costs exhibit great variation even within the areas judged by ERCB to be 'similar'. Although the original data on which this analysis is based are thought to be quite reliable, the resulting cost estimates could vary considerably in individual situations. The foothills relation is quite questionable since it is based on only seven observations. In fact, this is the only case in which we accepted and incorporated industry objections. The calculated costs at the 15,000 foot plus depth were viewed as too high and we accepted the average of the suggested costs, around $400 per foot. The plains and northern/central relations are somewhat more reliable being based on 100 and 309 observations respectively. In spite of some minor disagreement from various companies regarding costs at various depths, we stayed with our own estimates since the number of observations included makes them more reliable than individual company figures. Nonetheless, our procedure for incorporating completion costs is not precise and the escalation factor of 26 percent per year, suggested by the Canadian Petroleum Association, may be in error.

B.2 General Operating Costs

Operating costs are estimated per well (including existing equipment) in Table B.3. They include costs of labour, materials, maintenance, fuel, transportation, land rentals, and professional services. Workovers are normally considered an operating cost but are here included separately due to the extensive workovers and conversions expected in enhanced recovery operations (Tables B.4 and B.5). Table B.6 presents estimates of the percentage of wells that would require workover and conversion. Overhead and administration costs are also normally included as operating costs but are estimated separately here as discussed below.

TABLE B.3

GENERAL WELL OPERATING COSTS
$/well/year

	Well Depth in Feet				
	0-2,500	2,500-5,000	5,000-7,500	7,500-10,000	10,000+
Central Southern (Plains)	7,500	10,000	15,000	15,000	20,000
Northern	14,000	18,000	27,000	27,000	33,000
Foothills	14,000	18,000	27,000	27,000	33,000
Incremental Injection	4,000	6,000	8,000	8,000	17,000

SOURCE: Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.

TABLE B.4

WORKOVER AND CONVERSION COSTS
PRODUCER TO PRODUCER
$/well

Area	Depth	Period of Installation		
		Pre 1950	1950-1964	1965-1978
Plains	0-2,500	19,800	15,000	11,300
	2,500-5,000	33,900	26,200	20,300
	5,000-7,500	70,500	55,800	41,100
	7,500-10,000	110,000	95,000	82,000
	10,000+	200,000	175,000	145,000
Northern/Central	0-2,500	42,800	33,200	23,600
	2,500-5,000	77,400	65,800	46,400
	5,000-7,500	110,100	86,200	61,100
	7,500-10,000	120,100	96,200	92,100
	10,000+	205,000	180,000	150,000
Foothills	0-2,500	42,800	33,200	23,600
	2,500-5,000	77,400	65,800	46,400
	5,000-7,500	110,100	86,200	61,100
	7,500-10,000	120,100	96,200	72,100
	10,000+	205,000	180,000	150,000

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.

TABLE B.5

WORKOVER AND CONVERSION COSTS
PRODUCER TO INJECTOR
($)

Area	Depth	Period of Installation Pre 1950	 1950-1964	 1965-1978
Plains	0-2,500	15,000	12,500	10,000
	2,500-5,000	23,600	19,800	16,000
	5,000-7,500	49,900	42,900	35,800
	7,500-10,000	70,100	82,100	76,000
	10,000+	195,000	173,000	148,000
Northern/Central	0-2,500	31,500	26,200	21,000
	2,500-5,000	59,400	70,000	39,900
	5,000-7,500	75,000	84,000	52,400
	7,500-10,000	91,500	100,000	68,400
	10,000+	210,100	192,000	160,000
Foothills	0-2,500	31,500	26,200	21,000
	2,500-5,000	59,400	70,000	39,900
	5,000-7,500	75,100	84,000	52,400
	7,500-10,000	91,500	100,000	68,400
	10,000+	210,100	190,000	160,000

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.

2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.

3) Oil industry representatives, confidential revisions and updates.

TABLE B.6

PROPORTION OF WELLS REQUIRING CONVERSION

Period of Installation	% of Wells Requiring Workover
Pre 1950	100
1950-1964	50
1965-1977	25
Post 1977	0

SOURCE: National Petroleum Council, Enhanced Oil Recovery, December 1976, p. 85.

Overhead and administration

These costs are not reported separately in the models, but are calculated at 20 percent of operating costs and 4 percent of capital costs and included as part of total costs. These amounts were suggested in the Lewin and Associates study, The Potential and Economics of Enhanced Oil Recovery, p. v.11. The 4 percent levy on total capital costs as defined in this study is quite high but it includes a risk premium of approximately 2 percent as discussed in Section 4.6.3.

Injection materials costs

A number of cost estimates for various chemicals used in the polymer, alkaline, and micellar flood were obtained. The costs used in the models are discussed in Section B.3.

B.3 Capital, Operating and Materials Costs Specific to Each Process

B.3.1 Steam Drive and Steam Stimulation

Specific costs associated with these processes are steam generators and pollution abatement equipment. The capital cost of the generator is based on a 50,000 lb/hr unit capable of generating 1.25 million barrels of steam a year. The assumed fuel is lease crude priced at the assumed oil price with the amount required derived from the Btu requirements to generate one barrel of steam. This varies by temperature and pressure but, assuming an average of 520,000 Btus required per barrel of steam and applying the thermal content of a barrel of 20° API crude oil of 6.24 million Btus, we require 0.083 barrels of oil per barrel of steam.[1] This is equivalent to one barrel of oil per 12 barrels of steam. Operating costs cover maintenance, chemicals and inlet water treating at approximately $250,000 per year ($0.20 per barrel of steam produced). Pollution control equipment to gather and incinerate casinghead gas and to remove the steam plume from scrubbers is also costed in Table B.7. Injection and production equipment for thermal processes must be heavily insulated for safety and to conserve heat. Based on industry advice, we cost them at two times the costs of standard equipment (from Table B.1).

TABLE B.7

STEAM DRIVE AND STEAM STIMULATION

Item	Cost
Generator costs (50,000 lb/hr unit)	$400,000
Operating costs (excluding fuel)	$0.20/bbl of steam
Fuel costs (per barrel of steam)	$0.088 x (price/bbl of oil)
Gathering casinghead gas	$4,000 per producing well
Pollution abatement (steam plume removal)	$50,000 per generator
Injection and production equipment	all elements in Table B.1 are multiplied by two to allow for insulation requirements

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.

B.3.2 In-Situ (Wet) Combustion

Air compressor costs are based on a 325 bhp unit capable of producing one million standard cubic feet per day (1 MMscfd) of compressed air. Operating costs, excluding fuel, range from $20,000 to $45,000 a year ($0.08/Mcf of air compressed). Lease crude is used as fuel and the requirements are determined on the assumption that the unit requires 10,000 Btu/hp/hr.

Fuel Requirement Calculation

1 325 hp compressor produced 1 MMscf/day using 10,000 Btus/hp/hr = 78,000,000 Btus/day.

1 barrel of 20° API crude oil provides 6.24 million Btus therefore 12 barrels of oil are required per day, or 0.0125 bbls/Mcf of air compressed.

Injection and production equipment are estimated at twice the costs of non-thermal processes due to insulation requirements. In addition $15,000 per pattern is allowed for high pressure line. Produced oil requires treating at $10 per thousand barrels to prepare it for further processing.

Pollution abatement equipment required to scrub the vent gas to reduce sulfur emissions is costed at $9 per Mscf/d of gas handled (assumed to be the same as gas injected). This includes $3 per Mscf/d for cases where elimination of the steam plume from the scrubbers is necessary.

A treatment allowance of $0.03 per Mscf/d is included, to offset the effects of the corrosive produced gases on the gathering system. These costs are summarized in Table B.8.

TABLE B.8

IN SITU COMBUSTION

Item	Costs
1 MMscfd compressor (325 bhp @ $900/hp)	$292,500
0.5 MMscfd compressor (160 bhp @ $900/hp)	$146,250
Operating costs (excluding fuel)	$0.08/Mcf
Fuel costs	$0.0125 x (price of oil) /Mcf
High pressure air injection lines	$15,000 per pattern
Gathering & incinerating casinghead gas	$4,000 per pattern
Pollution abatement (reduce sulfur emissions & eliminate steam plume)	$9/Mscfd
Corrosion Treatment	$0.03/Mscf/yr
Oil treatment	$0.01/bbl.
Injection and production equipment	all elements in Table B.1 are multiplied by two to allow for insulation requirements

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.

B.3.3 Polymer Augmented Waterflood

Polymer costs were gathered from a number of sources.[2] Costs ranged from $1.60 per pound to $3.00 per pound delivered in Canada with the lower prices applying to polymers produced in the Alberta area. The average prices shown in Table B.9 assume that most of the polymer would be imported at the early stages of polymer development. As the scale of activity increased, however, it would seem likely that production would move into Canada reducing transportation costs and eliminating exchange costs. The composition of the assumed polymer solution is 50 percent polyacrylamides and 50 percent polysaccharides at a concentration of 250 PPM.

TABLE B.9

POLYMER AUGMENTED WATERFLOOD COSTS
(50% polyacrylamides, 50% polysaccharides)

Oil Price	Polymer Cost ($/lb)	Polymer Cost ($/bbl @ 250 PPM)
15.00	2.10	0.18
20.00	2.31	0.20
25.00	2.54	0.22
30.00	2.80	0.24
40.00	3.38	0.30
50.00	4.09	0.36

Other Costs: Water $0.05/bbl.

SOURCE: Calculated based on assumed price of $2.10/lb.

Pricing polyacrylamides at $1.70/lb and polysaccharides at $2.50/lb results in our average price of $2.10/lb. However, it is felt that very large scale production of polysaccharides would reduce their costs by one third or more.[3]

The table shows dependence of polymer costs on the price of oil reflecting the energy costs element in the production process.

B.3.4. Alkaline Flood

Special costs due to the need to acidize injection wells occasionally (because of the likelihood of injectivity problems otherwise) and to demulsify the produced oil-water emulsions are incorporated, as shown in Table B.10. The alkaline material used is assumed to be sodium hydroxide at a concentration of 15,000 PPM and is again dependent on oil price due to energy requirements in production. The polymer costs are the same as Table B.9.

TABLE B.10

ALKALINE FLOOD
(Injected materials are sodium hydroxide, polymer and water)

Sodium Hydroxide (NaOH) Costs

Oil Price	NaOH Cost ($/lb)	NaOH Cost ($/bbl @ 15,000 PPM)
15.00	0.13	0.68
20.00	0.14	0.74
25.00	0.16	0.85
30.00	0.18	0.95
40.00	0.20	1.06
50.00	0.23	1.20

Calculated on assumed price of $0.13/lb.

Polymer Costs (50% polyacrylamides, 50% polysaccharides)

Oil Price	Polymer Cost ($/lb)	Polymer Cost ($/bbl @ 250 PPM)
15.00	2.10	0.18
20.00	2.31	0.20
25.00	2.54	0.22
30.00	2.80	0.24
40.00	3.38	0.30
50.00	4.09	0.36

Other Costs:		
	Water	$0.05/bbl.
	Acidizing treatments	$1500/injection well
	Demulsification	$0.10/bbl.

SOURCE: Polymer costs, Table B.9. Alkaline costs calculated based on assumed price of $0.13/lb. Other costs from confidential industry estimates.

B.3.5 Microemulsion Flood

The surfactant slug costs are based on a composition of sulfonate (6.5 percent by weight), alcohol (1.0 percent by weight) and oil (10 percent by volume). All costs are related to the price of oil. The polymer costs per barrel in a microemulsion flood are higher than in other processes using polymer because of the higher concentration solution required. We assume a 600 PPM solution is used to prevent fingering into the surfactant slug. Alcohol costs are based on a combination of isopropanal, pentanol and hexanol. Table B.11 summarizes these costs for alternate prices of oil.

B.3.6 Carbon Dioxide Miscible Flood

Table B.12 presents costs for the CO_2 miscible process. Since we recycle produced CO_2 we incorporate separation and compression equipment at a cost of $4,000 per MMcf unit required. Purchased CO_2 is priced to include distribution at pressure (1,500 psig) and extra equipment costs are based on the required high pressure injection equipment, manifolds, tubing and safety equipment at $45,000 per injection well. Operating costs are higher in CO_2 floods because of the need to treat wells for corrosion and deposits. This cost was estimated at $7,000 per year per pattern. We also allow $0.05 per Mcf of CO_2 injected for sulfur removal.

The actual cost of CO_2 delivered to the field is assumed to vary according to which of our areas (Northern, Plains or Foothills) the field is located in. The costs are based loosely on a recent study of CO_2 availability from various sources which does not incorporate any payment to the 'owner' of the CO_2 (i.e., in some cases producers who produce CO_2 as a waste byproduct).[4] This may or may not be a reasonable assumption depending, perhaps, on the attitude taken by the government. Since the 'owners' would have no other market, they could demand payment only by exercising what we might loosely term 'monopolistic property rights' to their waste effluent. If CO_2 recovery was viewed to be potentially significant, but only if negligible costs for the CO_2 were guaranteed, the government might well ensure these negligible costs.

TABLE B.11

MICROEMULSION FLOOD

Injected materials begin with a surfactant slug consisting of a sulfonate (6.5% by weight), a cosurfactant (alcohol - 1% by weight) and oil (10% by volume). This is followed by a polymer buffer and chase water.

	Sulfonate		Alcohol		Oil	Total Surfactant Slug
	$/lb	$/bbl	$/lb	$/bbl	$/bbl	$/bbl
15.00	0.45	10.24	0.28	0.98	1.55	12.49
20.00	0.54	12.29	0.32	1.12	2.00	15.09
25.00	0.65	14.78	0.37	1.29	2.50	18.19
30.00	0.78	17.75	0.42	1.48	3.00	21.80
40.00	1.13	25.56	0.56	1.96	4.00	30.96
50.00	1.63	37.00	0.74	2.59	5.00	43.85

Polymer Costs (50% polyacrylamides, 50% polysaccharides)

Oil Price	Polymer Cost ($/lb)	Polymer Cost ($/bbl @ 600 PPM)
15.00	2.10	0.44
20.00	2.31	0.48
25.00	2.54	0.53
30.00	2.80	0.59
40.00	3.38	0.71
50.00	4.09	0.86

Water costs $.05 per bbl.

SOURCE: Calculated based on the price per lb for each item at the $15 oil price.

TABLE B.12

CARBON DIOXIDE MISCIBLE

Item	Costs
Separation and compression equipment	\$4,000/MMcf unit required
High pressure injection equipment	\$45,000/injection well
Extra operating costs (corrosion, etc.)	\$7,000/producer/year
Sulfur removal	\$0.05/Mcf injected
Purchased CO_2	
Plains (Area 1)	\$1.71/Mscf
Northern (Area 2)	\$1.10/Mscf
Foothills (Area 3)	\$1.71/Mscf
Recycled CO_2	\$0.40/Mscf

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.
4) Saturn Engineering, "Estimate of Cost of Recovery of CO_2," prepared for Alberta Department of Energy and Natural Resources, November, 1977.

B.3.7 Hydrocarbon Miscible

The hydrocarbon miscible process is assumed to operate on a basis almost technically identical to that of the CO_2 miscible process. Cost differences, shown in Table B.13, appear because of the manner in which the injection material is treated. Because most reservoirs involve gas production at the primary stage, gas plants and distribution lines are assumed to be in place so no recompression costs are required to inject the hydrocarbon, although some addition to plant capacity to handle increased gas production may be required. Extra capital costs for high pressure injection lines are included, however, at \$15,000 per pattern.

TABLE B.13

HYDROCARBON MISCIBLE

Item	Costs
High pressure air injection lines	\$15,000/pattern
LPG	crude oil price/bbl
Methane	$\$1.70/\text{Mcf} \times \frac{\text{oil price}}{(\$15.00)}$

SOURCE: 1) Lewin and Associates, The Potential and Economics of Enhanced Oil Recovery, prepared for Federal Energy Administration, April, 1976.
2) National Petroleum Council, Enhanced Oil Recovery, December, 1976.
3) Oil industry representatives, confidential revisions and updates.

NOTE: The expected 1979 price of natural gas, \$1.70/Mcf, maintains its proportionality to the price of oil in sensitivity runs by increasing by the factor shown.

The LPG injected is priced at the current crude price and the methane at the price of natural gas. We assume the injected LPG is recovered completely and the methane is 60 percent recovered in two years. The present value of the recovered hydrocarbons discounted at 10 percent is deducted from the materials costs in years two through ten. This is tantamount to assuming they are reinjected which is simply a more convenient way to handle them than to add them to production and revenue. The procedure also facilitates the royalty calculation which requires the value of materials net of the present value of their recovery value to be deducted from revenue before calculation of the royalty.

B.4 The Detailed Analysis of Drilling and Completion Costs

The statutory declarations report drilling and completion costs by well location and month for 1974, 1975 and 1976. To get drilling costs for 1977 ERCB deducted completion costs from total costs and escalated the result at a rate of 26 percent per year from the month in which the well was drilled. Completion cost estimates were derived from the detailed company reports but these reports do not follow a standard format and the allocation of some cost elements to drilling versus completion involves some judgment.

The reports were grouped in three regions, Northern/Central, Plains, and Foothills, following a preliminary analysis that suggested reasonable similarity of costs within these regions. To use these data to estimate development well costs for evaluating enhanced recovery projects we needed to estimate the contribution of completion costs to the total. However, in areas where road construction costs were significant it was felt that inclusion of this element would bias the cost estimate unduly upwards since, for enhanced recovery projects, it is likely that a minimum amount of new road construction will be needed.

The best approach to putting the available data in usable form would have been to deduct some estimate of road costs from the reported completion costs and add the result to the drilling costs. This total cost would then have to be escalated at some appropriate rate by month to the end of 1978. Then regression analysis could be used to analyse the resulting development costs. However, escalating each well cost to the present promised to be a time consuming operation and since ERCB had already provided graphs of drilling costs versus depth we decided to adjust these by some estimate of completion costs net of road costs.

Access to the detailed reports was limited since they are quite sensitive documents. We relied on visual analysis of the reports and conversations with ERCB and industry representatives to establish our assumption that road costs represented approximately 10 percent of completion costs in the Northern/Central and Foothills regions and were a negligible element in the Plains region. This amount was deducted from gross completion costs.

Inspection of the ERCB summary data suggested that the best approximation of completion costs we could devise would be the simple average of completion costs shown in the data over depth intervals. The results are given in Table B.14. These estimated completion costs were then added to the drilling costs in each area to determine total cost. This calculation is shown for individual areas in Tables B.15, B.16, and B.17. The calculated costs per foot are incorporated in the model as set out in Table B.2.

TABLE B.14

WELL COMPLETION COST ESTIMATES

Adjustment Factor Depth (000 feet)	Completion Costs Net of Road Costs ($000)
Northern/Central	
1 - 3	24
3 - 5	31
5 - 7	44
7 - 10	79
10+	132
Plains	
1 - 3	15
3 - 5	28
5+	40
Foothills	
All depths	12% of drilling costs (22% minus 10% for road costs)

SOURCE: Estimated from graphs and data provided by the Alberta Energy Resources Conservation Board.

TABLE B.15

PLAINS (AREA 1)

Depth	Drilling Costs Dec. 1978[a] ($000)	Completion Cost Adjustment Incorporated[b] ($000)	Total Cost ($/foot)
1,500	50.4	65.4	44.9
2,500	98.3	115.3	46.1
3,500	132.3	160.3	45.8
4,500	176.4	204.4	45.4
5,500	233.1	271.1	49.6
6,500	302.4	340.4	52.7
7,500	378.0	416.0	55.5
8,500	472.5	512.5	60.3
9,500	585.9	625.9	65.9
10,500	711.9	751.9	71.6
11,500	882.0	922.0	80.2
12,500	1058.4	1098.4	87.9
13,500	1285.2	1325.2	98.2
14,500	1575.0	1615.0	111.1
15,500	1927.8	1967.8	126.7
16,500	2318.4	2358.4	142.7

SOURCE: Estimated from graphs and data provided by the Alberta Energy Resources Conservation Board.

[a] December 1977 costs taken from ERCB graphs and escalated at a rate of 26 percent per year to December 1978.

[b] See Table B.14

TABLE B.16

NORTHERN (AREA 2)

Depth	Drilling Costs Dec. 1978[a] ($000)	Completion Cost Adjustment Incorporated[b] ($000)	Total Cost ($/foot)
1,500	100.8	124.8	83.2
2,500	151.2	175.2	70.0
3,500	201.6	232.6	66.5
4,500	264.6	295.6	65.7
5,500	340.3	384.3	69.8
6,500	453.6	497.6	76.6
7,500	579.7	658.7	87.8
8,500	756.1	835.1	98.2
9,500	982.9	1061.9	111.8
10,500	1260.0	1392.0	132.6
11,500	1613.0	1745.0	151.7
12,500	2092.0	2224.0	177.9
13,500	2640.0	2772.0	205.3
14,500	3403.0	3535.0	243.8
15,500	4474.0	4606.0	297.2
16,500	5797.0	5929.0	359.3

SOURCE: Estimated from graphs and data provided by the Alberta Energy Resources Conservation Board.

[a] December 1974 costs taken from ERCB graphs and escalated at a rate of 26 percent per year to December 1978.

[b] See Table B.14.

TABLE B.17

FOOTHILLS (AREA 3)

Depth	Drilling Costs Dec. 1978[a] ($000)	Completion Cost Adjustment Incorporated[b] ($000)	Total Cost ($/foot)
4,500	453.6	508.0	112.9
5,500	567.0	635.0	115.5
6,500	730.8	818.5	125.9
7,500	932.4	1044.3	139.2
8,500	1171.8	1312.4	154.4
9,500	1512.0	1693.4	178.3
10,500	1890.0	2116.8	201.6
11,500	2394.0	2681.3	233.2
12,500	3024.0	3386.9	271.0
13,500	3906.0	4374.7	324.1
14,500	5040.0	5644.8	389.3
15,500	6300.0	7056.0	455.2
16,500	8064.0	9031.7	547.4

SOURCE: Estimated from graphs and data provided by the Alberta Energy Resources Conservation Board.

[a] December 1977 costs taken from ERCB graphs and escalated at a rate of 26 percent per year to December 1978.

[b] See Table B.14.

Footnotes

[1] Thermal content, figures from Alberta Energy Resources Conservation Board, *Alberta Electric Industry, Cumulative Annual Statistics*, (Calgary: Alberta Energy Resources Conservation Board, 1976), 77-28.

[2] The primary source of polymer price quotations was correspondence from a number of chemical companies in Canada and the United States provided by the Petroleum Recovery Institute.

[3] Gulf Universities, *Chemicals for Microemulsion Flooding*.

[4] Saturn Engineering, "Estimate of Cost of Recovery of CO_2," (Edmonton: Alberta Department of Energy and Natural Resources, November 1977).

APPENDIX C

APPENDIX C

INCORPORATING TAX AND ROYALTY CONSIDERATIONS

We attempt to calculate income taxes and royalties on a project by project basis. This is only a general approximation of tax liability since the tax position of individual companies is unique. But the attempt is justified since, from the company viewpoint, taxes are relevant costs and although some years ago many companies were not taxable because of accumulated expenses for writeoffs, today almost all companies are in a taxable position. The company decision to undertake a project will, therefore, depend on the net revenue it generates after taxes and royalties. Since taxes and royalties are a transfer payment from companies to government rather than what economists call a 'real' cost of development, the socially desirable set of projects, providing maximized net value added at given prices, is independent of tax considerations. In other words, a 'perfect' tax system (in this context) would collect society's share of project revenue without affecting the viability of the project from the private developer's viewpoint. In the absence of such a system, fewer projects will appear financially feasible to a company that must consider the tax cost. Therefore, evaluating the potential for enhanced recovery both with and without tax and royalty considerations will allow some interesting comparisons and in particular will yield an estimate of how far short of optimal the actual future supply of oil from EOR projects will be, given a particular tax regime.

The tax and royalty regulations incorporated in the model are those of the federal government and the province of Alberta.[1] The regulations incorporated are those that were in place or announced in 1978 when the models were being developed and run. Some changes have occurred since then. For example, the investment tax credit was not included since it was scheduled to expire on July 1, 1980. It has now been extended indefinitely and if it remains in effect over the evaluation period used here, it means that our tax calculation may overstate tax by approximately 6 percent of qualifying expenditures.

C.1 Estimating Royalties

For purposes of modelling royalty considerations we referred to the petroleum royalty regulations, Alberta Regulation 93/74, dated April 1, 1974, and subsequent amendments to February 1978. Clarification is given in "Interim Guidelines for the Administration of Section 4.2 of the Petroleum Royalty Regulations," issued by Alberta Energy and Natural Resources, effective January 1, 1977.

The model assumes all projects will come under crown royalty regulations rather than the 'reserves tax' regulations which apply to freehold land. This is realistic since 82 percent of the relevant lands in Alberta are crown lands.

The royalty is calculated according to Equation 1, with all values set at their levels of September 1978.

$$\text{1)} \quad Roy = S + KS \frac{(A - B)}{A}$$

Roy = royalty in barrels

S = the number of barrels determined in accordance with Table C.2 below.

A = the par price of crude oil, set at $13.06.

B = the select price of crude oil, set at $4.71.

K is the royalty factor for the month. K differs for 'old' versus 'new' oil as defined in the petroleum regulations. However, all oil from enhanced recovery projects will qualify as 'new' oil and the K factor is set at 0.6303 (whereas K from 'old' oil is 1.5701). The value of K is changed as the price of crude oil changes to accommodate prevailing policy. Currently policy is to capture 35 percent of any price increases. The exact relationship between K and crude price for new oil may be determined from the following equation. P_1 is average production for the province currently taken as 3,600 barrels per well per month. The results of calculation of the value of K for various prices is presented in Table C.1.

TABLE C.1

PROJECTED RELATIONSHIP BETWEEN WELLHEAD CRUDE PRICE AND THE ROYALTY FACTOR K

Price	K
13.06	0.6303
14.06	0.6293
15.06	0.6283
15.50	0.6279
16.00	0.6275
17.00	0.6268
18.00	0.6267
19.00	0.6256
20.00	0.6251
21.00	0.6246
22.00	0.6242
23.00	0.6238
24.00	0.6234
25.00	0.6231
30.00	0.6218
40.00	0.6202
50.00	0.6192

New Oil, 1-Jul-75

$$\frac{R}{P_1} = \frac{S}{P_1} + \frac{S}{P_1} K_n \left(\frac{A-B}{A}\right) = \frac{\frac{S}{P_1} \quad C_1 + .35\ (C_2 + C_3)}{C}$$

where $\frac{R}{P_1}$ = the average royalty rate

$\frac{S}{P_1}$ = the basic royalty rate

$\$12.75 = C$ is the wellhead equivalent of A

$\$4.40 = C_1$ is the wellhead equivalent of B

$\$2.10 = C_2$ is $\$6.50 - C_1$

$\$6.25 = C_3$ is $C - (C_1 + C_2)$

e.g. $$\frac{780}{3600} (1 + K_n \quad \frac{13.06 - 4.71}{13.06}) = \frac{\frac{780}{3600}\ 4.40 + .35\ (8.35)}{12.75}$$

TABLE C.2

Monthly Production in Barrels	Portion of Crown Royalty Payable for the Month in Barrels
0 - 1,200	The number of barrels determined by dividing the barrels produced by 120 and adding 5 to the quotient then multiplying by the barrels produced and dividing by 100.
1,200 and over	180 barrels plus one-fourth of the number of barrels produced in excess of 1200 barrels.

SOURCE: Taken from Alberta Regulation 93/74, the Alberta Gazette, April 15, 1974.

Our model calculates production per well per day which is multiplied by 30 to get production per month (later we calculate the yearly royalty by multiplying the monthly result by 12.17 = 365 ÷ 30). Using monthly production we determine the value of S from Table A, plug it into the formula to get gross royalties per well per month in barrels which is then multiplied by the number of producing wells in the project and by 12.17 to give us gross royalties per year in barrels. This figure is divided by production for that year to get the royalty in fractional terms. This is necessary because of the manner in which eligible cost deductions are taken into account. They are to be deducted from total revenue before the calculation of royalties. Thus we take total revenue, deduct eligible costs, and multiply the result by the fractional royalty figure.

Alberta regulation 9/77, an amendment to the regulations on enhanced recovery, outlines the cost deduction as significant incremental costs plus 10 percent. Significant incremental costs (beyond waterflood costs) are defined to include the value of hydrocarbons injected or used as fuel, the value of other injected fluids and chemical additives and the cost of purchased energy including allowance for transportation of the above. The present value of injected hydrocarbons expected to be recovered in the future must be deducted from this. In addition, incremental capital costs can be amortized at a rate of 10 percent on the diminishing balance. Eligible capital items include wells and well conversions, pumps, compressors, mixing facilities, pipelines, storage facilities, and steam generating facilities as well as interest on construction at the prevailing prime rate plus one. The current prime rate was 9.75 percent in September 1978, but it fluctuates according to economic conditions and we have assumed a rate of 9 percent for our calculations. This is applied to total pre-production development costs.

A summary example of the royalty calculation is presented in Table C.3.

TABLE C.3

ROYALTY CALCULATION EXAMPLE

1. Production per well per month (PRM)

$PRM = PR \times 30$ PR = production per well per day

2. $S = (5 + \frac{PRM}{120}) \frac{PRM}{100}$ IF PRM is 0-1200 bbl/month

$S = 180 + 0.25\ (PRM - 1200)$ IF PRM is greater than 1200 bbl/month

3. Gross royalty per well per month in barrels (GRoy/w/m)

$GRoy/w/m = S + KS\ \frac{(A-B)}{A}$

where S = number of barrels determined from basic royalty schedule (Table C.1)
K = royalty factor for new oil (0.6303)
A = par price (13.06)
B = select price (4.71)

4. Gross royalty per year in barrels (GRoy/y)

$GRoy = GRoy/w/m \times wp \times 12.17$

wp = number of producing wells
12.17 = no. of 30 day months per year

5. Royalty as a percent of production

$GR\% = \frac{GRoy/y}{py}$ py = production per year

6. Sum eligible incremental costs + 10% (ICR cost)

a) CM (cost of material injected)
b) CCW amortized at 10% on reducing balance (capital costs)
c) 0.5 x OCW (energy cost of operating wells)
d) TC x 10% (interest on debt at prime (9%) + 1, the opportunity cost of funds committed to development.
e) (a + b + c + d) x 10% (allowance for other expenditures)

7. Calculate net royalty in dollars

$Roy\$ = (TR - ICR\ cost)\ GR\%$

NOTE: If incremental costs exceed TR in any year they may be carried forward to the next year.

C.2 Estimating Taxes

Tax estimation is less reliable than royalty estimation since every company is in a unique situation regarding available write offs, etc. Furthermore, the tax situation is quite complicated due to many recent changes that affect specific areas of a company's operation. However, an estimate of the tax liability of each project is possible as outlined below.

We calculate total revenue from the project in a year and deduct all eligible expenses. Federal and provincial rates of tax are applied to the result and any provincial rebates are incorporated. (In particular, the federal decision to disallow provincial royalties as a deduction has resulted in the province rebating 11 percent of the royalty payment net of federal resource allowance as a compensation.)

The complications in this procedure have to do with identifying the appropriate expenses. These generally include:

a) operating costs (including overhead)
b) depreciation (capital cost allowance) plus Canadian development expense
c) resource allowance
d) interest
e) depletion allowance.

Canadian Development Expenses and Depreciation

Portions of capital costs are deductible under two different categories, Canadian development expenses, which were separated from exploration expenses on May 7, 1974, and capital cost allowances, the income tax designation for depreciation. Both categories are written off at the rate of 30 percent on a declining balance.

Canadian development expense includes two main items: certain elements of capital costs (most notably well casing) and resource property acquisition costs. For tax purposes the latter deduction is likely used up at the primary and secondary stage of the field development. The eligible elements of acceptable capital costs are deducted at a rate of 30 percent on a diminishing balance.

The other major category is depreciation. Depreciable assets generally include above ground equipment and sucker rods and pumps. As noted above, well casing is considered a development expense. Since the two categories are handled in the same way we have combined them and expense total capital costs at the rate of 30 percent per year on the diminishing balance.

Resource Allowance

Effective January 1, 1976, a deduction to offset a portion of provincial levies was introduced. It is 25 percent of revenue after deducting operating costs and depreciation. For purposes of this calculation we assume that depreciation accounts for 60 percent of the eligible capital deduction (the remaining 40 percent is accounted for under Canadian development expense). The resource allowance is therefore calculated as 25 percent of total revenue minus the sum of operating costs and 60 percent of capital costs expensed at a rate of 30 percent on the diminishing balance. If resource allowances become negative, they are set to 0.

Depletion Allowance

This deduction from income for tax purposes was incorporated into the tax rules to allow for the fact that oil company 'inventories' will gradually be depleted. Under new regulations proposed in the summer of 1978, companies earn depletion dollars at the rate of one for every two dollars expended prior to the start of production. For EOR projects, the maximum deduction under the depletion allowance is now 50 percent of net income from all sources. We therefore deduct the lesser of one half of capital costs or one half of revenue net of all other expenses, whichever is less. The deduction can be carried forward indefinitely.

Rebates

The Alberta Royalty Tax Rebate of 11 percent of disallowed crown charges after deduction of the resource allowance is included in the model. In practice this amount is multiplied by an average of the fraction of the company's taxable income allocated to Alberta and the fraction of wages and salaries allocated to Alberta. In the model, since each project is assessed independently, we have assumed this fraction is 1. The rebate is first used to reduce provincial taxes and any excess is incorporated in the following year. There is also a rebate called the Royalty Tax Credit, formerly called the Small Explorers Tax Credit, which amounts to 25 percent of royalties up to a maximum of one million dollars in any year. If this amount is greater than tax payable after deducting rebates the balance is remitted to the taxpayer in cash. This is not incorporated in the model since it applies to total royalties paid by a company and the proportion attributable to EOR projects is indeterminate but probably relatively small.

Calculation of Taxes

The federal tax rate is 46 percent minus a 10 percent abatement for provincial tax. In addition, Canadian controlled private corporations get a further abatement of 21 percent on the first $150,000 of annual taxable income to a cumulative total of $750,000. This special abatement is not incorporated in the model since it would not apply to the majority of EOR project operators and in any event the total will likely be used up for most operators by the time significant enhanced recovery operations are starting up. Thus federal tax is calculated at 36 percent of taxable income. Business losses due to operating and capital costs exceeding income in any year may be carried forward for a period of five years.

Provincial tax in Alberta is 11 percent of taxable income and from this we deduct the provincial rebate.

Net Revenue

Total revenue minus taxes and royalties is entered into the net present value calculation to determine the viability of each project.

A summary example of the tax calculation is presented in Table C.4.

TABLE C.4

INCOME TAX CALCULATION EXAMPLE

1. Calculate eligible deductions to determine taxable income

   a) Operating and overhead costs and costs of materials

   b) Depreciation and the relevant portion of Canadian development expense (depreciation would not apply to the labour portion of CCW (approximately 20 percent) or to casing. Canadian development expense would not apply to tangible capital. But together, these items approximate capital costs. Thus total capital costs are written off at the rate of 30 percent on a diminishing balance.

   c) Resource Allowance (RA)

   RA = 0.25 x [TR - (item a and 0.6 x item b)]
   where TR = total revenue

   d) Interest CCW x (prime + 1)

   where CCW = capital costs

   e) Depletion Allowance

   0.5 (TR - OCW - OHC - CM - Deprec. - RA - Int)
   or
   0.5 CCW whichever is less

   where OCW = well operating costs
   OHC = overhead costs
   CM = cost of injected materials

2. Taxable Income = TR - (items a - e)

3. Calculate taxes

   Federal tax (FT) = 0.36 TI

   Provincial Tax (PT) = 0.11 TI - 0.11(Roy$ - RA)

4. Calculate net revenue (NTR) = TR - FT - PT - Roy$

   NTR now enters the calculation of net present value to determine whether or not the project is commercially viable.

Footnotes

[1] The following sources were used in developing the royalty and tax section of the model:

a. Alberta Regulations

Petroleum Royalty	April, 1974	Regulation # 93/74
Amended	Oct., 1974	251/74
Amended	Sept., 1976	243/76
Amended	Jan., 1977	9/77
Par and Select Prices	Aug., 1977	206/77
Amended	Feb., 1978	28/78

b. *Interim guidelines for the administration of Section 4.2 of the Petroleum Royalty Regulation*, Alberta Energy and Natural Resources, May 31, 1977, amende June 29, 1977.

c. David E. Lewis and Andrew R. Thompson *Canadian Oil and Gas*, Butterworth & Co. (Canada) Ltd., Toronto.

d. Alberta Energy Resources Conservation Board, *Computational Methods of the Assessor for Assessment of Petroleum Rights Under the Freehold Mineral Taxation Act and for Assessment of Oil and Gas Properties Under the Oil and Gas Conservation Act*, (Alberta Energy Resources Conservation Board) March, 1974.

e J. B. Kathlen and R. W. Bowhay, *Federal Oil and Gas Taxation*, (Canada: Richard de Boo Limited, 1973).

f. Royal Bank of Canada "Taxation - Bulletin No. 9" (Canada: The Royal Bank of Canada, Oil and Gas Department, March, 1972.)

APPENDIX D

APPENDIX D

DETAILED DESIGN OF PRODUCTION MODELS FOR SPECIFIC PROCESSES

D.1 Steam Drive

Assumptions

A1) Incremental recovery is determined as described in 4.3 using

$$R = \frac{S_{orw} - S_{ort}}{S_{orw}} \times \text{ROIP}$$

which is then multiplied by 0.92 to get incremental recovery (IR).

A2) A five spot is assumed.

A3) Pattern size (the number of acres serviced by one production well) is 5 acres.

A4) The productive life of a pattern is 7 years.

A5) The time profile of production over the 7 years is:

Year	1	2	3	4	5	6	7
% of Prod.	0	10	20	22	22	16	10

A6) The time profile of steam injection over the 7 years is:

Year	1	2	3	4	5	6	7
Number of Pore Volumes Injected	.25	.2	.2	.2	.2	.2	.2

Technical Relationships

T1) Calculation of required wells

From A2 the implied ratio of injection wells to production wells is 0.8. This allows calculation of total wells required as follows:

Production wells (WP) = No. of patterns = total acreage ÷ pattern size

Injection wells (WI) = WP x 0.8

T2) Calculation of steam generating equipment required

The pore volume for the entire reservoir is calculated as total volume times porosity.

$$PV = \emptyset Ah$$

where
PV is pore volume
$\emptyset$ is reservoir porosity
A is acreage of reservoir
h is pay thickness

The pore volume is allocated to each production stage (Section 4.4) according to the percentage of production assigned to that stage and is multiplied by 7,758 to translate it into barrels.

Applying the time profile of injection rates to each stage yields the number of barrels of steam required in each year. From this we determine the maximum daily requirement of steam in barrels, translate it to pounds and then calculate the number of Btus required to convert that many pounds of water to steam at the pressure and temperature conditions found in the reservoir. Conversion factors are taken from, Introduction to Chemical Engineering Thermodynamics, J.M. Smith and H.C. VanNess, 1975, Appendix C.

The purpose of the above calculation is to allow us to determine how many steam generators of a given capacity are required to meet the maximum requirements in any stage of production. This number then becomes a component of the capital cost calculation for the steam drive process.

D.2 Cyclic Steam Stimulation

This model differs from the others because the recovery method itself is somewhat different. Therefore we have adopted a generalized set of production assumptions, described below, that are derived more from field experience than from theoretical considerations.[1]

Assumptions

A1) Incremental recovery is 25 percent of original oil in place.

A2) Area served by each well is 5 acres.

A3) Required steam/oil ratio is four barrels steam per barrel of oil produced.

A4) During the production period of the cycle the production rate is 65 barrels per day per well.

A5) Cycles include increasing injection periods and decreasing production periods as follows:

Cycle	Injection Time (days)	Shut In Time (days)	Production Time (days)	Total Time
1	10	10	20	40
2	15	10	25	60
3	20	10	30	60
4	25	10	30	65
5	25	10	30	65
6	25	10	35	70
	120	60	170	360

Technical Relationships

T1) Calculation of production period in years.

Well life in years is variable in this process rather than an assumed amount as in the other processes. It is calculated in three steps:

1) Calculate number of wells required as total acreage divided by the number of acres serviced by each well, here assumed to be 5.

2) Calculate total production per well by dividing incremental recovery by wells required.

3) Calculate well life in years by dividing total production per well by production per year.
(65 bbls/day x 170 producing days)

T2) Calculation of yearly well requirements.

The minimum number of wells to be developed in any stage of field development is five. Since all stages of production are assumed to begin one year after the beginning of the previous stage, the field life can be determined as the number of stages (1/5 x wells required) plus well life minus one. We assign a maximum possible field life of 16 years and, if calculated field life exceeds this amount, the number of wells per stage is increased until the 16 year field life is achieved. It is possible under this formulation for the well life to exceed the calculated field life. If this happens, the model arbitrarily assigns a field life equal to well life.

T3) Calculation of steam generation equipment required.

Estimated incremental recovery is divided equally among the number of stages and the number of years of well life. Then for each year the required amount of steam (4 x no. of barrels of oil produced) is translated to Btus required and used to calculate the number of generators required as in T2 of the steam drive model.

D.3 In Situ Wet Combustion

Assumptions

A1) Incremental recovery is determined as described in 4.3 using:

$$R = \frac{S_{orw} - S_{ort}}{S_{orw}} \times \text{ROIP} - \text{oil burned in the combustion zone}$$

The slight alteration in the formula is because some of the oil is consumed by the combustion process. The amount varies with viscosity. When viscosity is less than 40 cp, 180 barrels of oil per acre foot are assumed lost in combustion. When viscosity is greater than 40 cp, 240 barrels per acre foot are assumed burnt. These amounts are deducted from the estimate of R which is then reduced by 8 percent to allow for irregular edge problems.

A2) A nine spot pattern is assumed.

A3) Pattern size is 20 acres.

A4) The productive life of a pattern is 7 years.

A5) The time profile of production over the 7 years is:

Year	1	2	3	4	5	6	7
% of Prod.	10	15	21	19	16	12	7

A6) The time profile of air and water injection over the 7 years is:

a) For reservoirs with oil viscosity greater than 40 cp, air injection is 3.0 MMscf/yr per acre foot of burn.

b) For reservoirs with oil viscosity less than 40 cp, air injection is 2.5 MMscf/yr per acre foot of burn.

c) In both a) and b) water injection is 0.5 barrels per Mscf of air injected per year.

Technical Relationships

T1) The assumed nine spot pattern implies a ratio of injection wells to production wells of 0.3.

T2) Air injection requirements are met by the required number of 0.5 MMscfd units (160 BHP).

Number of compressors = [MMscf/yr required ÷ (365)] ÷ 0.5

D.4 Polymer Augmented Waterflood

This model differs from the others primarily because only sweep efficiency, not displacement, is assumed to be affected by a polymer flood.

Assumptions

A1) Incremental recovery is assumed to be 15 percent of primary plus secondary production in all cases where secondary production has been forecast by the Energy Resources Conservation Board. In cases where no forecast for secondary production has been made, incremental recovery is assumed to be 5 percent of original oil in place. This amount is multiplied by 0.92 to allow for sweep inefficiencies at the edge of the pool.

A2) A five spot pattern is assumed.

A3) Pattern size is 80 acres.

A4) The productive life of a pattern is assumed to be 10 years.

A5) The time profile of production over the 10 years is:

Year	1	2	3	4	5	6	7	8	9	10
% of Prod.	0	5	10	20	20	15	10	10	5	5

A6) The time profile of injection of water and polymer over the 10 years is:

Year	1	2	3	4	5	6	7	8	9	10
Number of Pore Volumes Injected										
Polymer	.05	.05	.05	.05	0	0	0	0	0	0
Water	0	0	0	0	.05	.05	.05	.05	.05	.05

Technical Relationships

T1) The polymer (in lbs) required to obtain a 250 PPM solution is calculated as follows:

42 gals/bbl x 0.1336 cu.ft/gal x 62.4 lbs/cu.ft =
350.13888 lbs/bbl

A 250 PPM polymer solution rquires 350.13888 x 0.00025 = 0.0875 lbs of polymer per barrel.

D.5 Alkaline Flood

Assumptions

A1) Incremental recovery is determined as described in 4.3 using

$$R = \frac{S_{orw} - S_{ort}}{S_{orw}} \times ROIP$$

Incremental recovery is R x 0.92 which allows for sweep inefficiencies at the reservoir edges.

A2) A five spot pattern is assumed.

A3) Pattern size is 40 acres.

A4) The productive life of a pattern is 10 years.

A5) The time profile of production is:

Year	1	2	3	4	5	6	7	8	9	10
% of Prod.	0	1	7	16	21	21	16	11	5	2

A6) The time profile of injection of the alkaline solution, a chase polymer solution and water is shown below.

Alkaline Injection Schedule (pore volumes injected per year)

Year	1	2	3	4	5	6	7	8	9	10
Sodium hydroxide sol.	.08	.08	.08	0	0	0	0	0	0	0
Polymer solution	0	0	0	.05	.05	.05	.05	0	0	0
Water	0	0	0	0	0	0	0	.05	.05	.05

Technical Relationships

T1) Calculation of wells required

From A2 the implied ratio of injection wells to production wells is 0.8. Total wells required equals production wells (WP) plus injection wells (WI), where

WP = total acreage ÷ pattern size
WI = 0.8 x WP

From this total we subtract the projected number of wells that will be in place following waterflood (as discussed in Section 4.4) which yields the number of new wells that must be drilled to develop the reservoir.

T2) Calculation of number of lbs per barrel of sodium hydroxide and polymer needed to obtain the solution concentration required (i.e. 1,500 PPM alkaline solution and 250 PPM polymer solution).

1) Alkaline
42 gals/bbl x 0.1336 cu.ft/gal x 62.4 lbs/cu.ft =
350.13888 lbs/bbl
350.13888 lbs/bbl x 0.015 = 5.252 lbs/bbl

2) Polymer
350.13888 lbs/bbl x 0.00025 = 0.0875 lbs/bbl

D.6 Microemulsion Flood

Assumptions

A1) Incremental recovery is, as described in 4.3, equal to

$$\frac{S_{orw} - S_{ort}}{S_{orw}} \times \text{ROIP} \times 0.92$$

A2) A five spot pattern is assumed.

A3) Pattern size is 20 acres.

A4) The productive life of a pattern is 8 years.

A5) The time profile of production is

Year	1	2	3	4	5	6	7	8
% of Prod.	0	0	10	24	29	20	10	7

A6) The time profile of injection of the sufactant slug, the polymer chase solution and water is shown below.

Surfactant Injection Schedule (pore volumes injected per year)

Year	1	2	3	4	5	6	7	8
Surfactant slug	.085	0	0	0	0	0	0	0
Polymer solution	0	.75	.75	.75	0	0	0	0
Water	0	0	0	0	.75	.75	.75	.75

Technical Relationships

T1) From A2 the implied ratio of injectors to producers is 0.8. Total wells required equals production wells (WP) plus injection wells (WI), where

WP = total acreage ÷ pattern size
WI = 0.8 x WP

From the total we subtract the projected number of wells that will be in place following waterflood (as discussed in Section 4.4) which yields the number of new wells that must be drilled to develop the reservoir.

T2) The sulfonate consists of a 100 percent active surfactant 6.5 percent by weight, a cosurfactant (alcohol) 1.0 percent by weight and oil, 10 percent by volume.

The polymer solution requires a concentration of 600 PPM in this process.

The amounts of the various chemicals required per barrel are therefore:

Surfactant
42 gals/bbl x 0.1336 cu.ft/gal x 62.4 lbs/cu.ft = 350.13888
350.13888 lbs/bbl x 0.065 = 22.759 lbs/bbl

Cosurfactant (alcohol)
350.13888 x 0.01 = 3.501389 lbs/bbl

Oil
0.1 bbl/bbl.

Polymer
350.13888 x 0.0006 = 0.21 lbs/bbl

D.7 Carbon Dioxide Miscible Flood

Assumptions

A1) Incremental recovery is determined as described in 4.3. We use

$$R = \frac{S_{orw} - S_{ort}}{S_{orw}} \times \text{ROIP}$$

This is multiplied by 0.92 to get incremental recovery (IR).

A2) A five spot pattern is assumed.

A3) Pattern size is 80 acres.

A4) The productive life of a well is 12 years.

A5) The time profile of production is:

Year	1	2	3	4	5	6	7	8	9	10	11	12
% of Prod.	0	0	4	7	11	15	18	14	12	10	6	3

A6) The time profile of injection involves both purchased and recycled CO_2 and water. CO_2 and water injection is alternated every 6 months. The injection schedule differs according to whether the reservoir is in a sandstone or carbonate formation with the latter requiring a slightly larger percentage of pore volume injection.

Injection Schedule in Sandstone Reservoirs (pore volumes injected per year)

Year	1	2	3	4	5	6	7	8	9	10	11	12
Purchased CO_2	.02	.02	.02	.018	.016	.014	.012	.01	.008	.008	.007	.006
Recycled CO_2	0	0	0	.002	.004	.006	.009	.01	.012	.012	.013	.014
Water	.02	.02	.02	.02	.02	.02	.02	.02	.02	.02	.02	.02

Injection Schedule in Carbonate Reservoirs

Year	1	2	3	4	5	6	7	8	9	10	11	12
Purchased CO_2	.025	.025	.025	.023	.021	.019	.017	.015	.014	.013	.012	.011
Recycled CO_2	0	0	0	.002	.004	.006	.008	.01	.011	.012	.013	.014
Water	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025	.025

Technical Relationships

T1) Calculation of wells required

From A2 the implied ratio of injection wells to production wells is 0.8. This allows calculation of total wells required as production wells (WP) + injection wells (WI), where

WP = total acreage ÷ pattern size
WI = 0.8 x WP

From this total we subtract the projected number of wells that will be in place following waterflood (as discussed in Section 4.4) which yields the number of new wells that must be drilled to develop this reservoir.

T2) Calculation of on-site units required for separating and recompressing recycled CO_2.

This is simply the number of cubic feet of recycled CO_2 required per year divided by 1 million. This yields the number of MMcf/year units required.

T3) Calculation of the number of cubic feet of CO_2 equivalent to a reservoir barrel of CO_2 at given depths and temperatures.

This is a two stage procedure as outlined below.

Stage 1: Calculation of reduced pressure (Pr) and temperature to allow identification of an approximate z value from a generalized compressibility chart.

1) $$Pr = \frac{P}{Pc \times 14.696}$$

where
P is 1/2 (0.6 x depth + 50) psi
Pc is critical pressure for CO_2, 72.8 atmospheres or 72.8 x 14.696 psi

2) $$TR = \frac{T + 460}{Tc \times 1.8}$$

where
T is reservoir temperature ^{o}F, converted to absolute temperature by the addition of 460.
Tc is the critical temperature for CO_2, 304.2^{o} Kelvin converted to absolute temperature by multiplying by 1.8

3) Given Pr and Tr we can read the compressibility factor, z, from a generalized compressibility chart.[2]

Stage 2: Calculating the volume of CO_2 equivalent to a reservoir barrel at a given depth and temperature (bbl vol)

4) $$V = \frac{z\,R(T + 460)}{P} \qquad \frac{\text{cu. ft}}{\text{lb mole}}$$

where
V is volume

z is compressibility factor $\left(\frac{psi}{^{o}R}\right)$

R is universal gas constant which is 10.73 $\left(\frac{\text{psia cu.ft}}{\text{lb mole } ^{o}R}\right)$

P is reservoir pressure (psi)

5) $$\text{bbl vol } (CO_2) = \frac{5.6145 \text{ cu.ft/bbl} \times 379 \text{ cu.ft/lb mole}}{V \text{ lb mole/cu.ft}}$$

$$= \frac{5.6145 \times 379}{V}$$

This calculation was carried out for various depths and temperatures and the result incorporated in the production model for CO_2 miscible injection.

D.8 Hydrocarbon Miscible Model

Assumptions

A1) Incremental recovery is determined as described in 4.3 using

$$R = \frac{S_{orw} - S_{ort}}{S_{orw}} \times ROIP$$

This is multiplied by 0.92 to get incremental recovery (IR).

A2) A five spot pattern is assumed.

A3) Pattern size is 80 acres.

A4) The productive life of a well is 12 years.

A5) The time profile of production is:

Year	1	2	3	4	5	6	7	8	9	10	11	12
% of Prod.	0	0	4	7	11	15	18	14	12	10	6	3

A6) The time profile of injection involves an LPG slug, a chase gas, and water (which is injected alternately to the LPG slug and following the chase gas). This is not particularly suggested as a flooding pattern but rather was chosen as the highest cost pattern (thus the most conservative for estimating purposes) with the best chance of success.

Injection Schedule in Both Sandstone and Carbonate Reservoirs
(pore volume injected by year)

Year	1	2	3	4	5	6	7	8
LPG slug	0	.025	.025	.025	.025	0	0	0
Gas (methane)	0	0	0	0	0	.07	.07	.07
Water	.025	.025	.025	.025	.025	0	0	0

Year	9	10	11	12
LPG slug	0	0	0	0
Gas (methane)	.07	0	0	0
Water	0	.025	.025	.025

A7) Injected hydrocarbons are recovered in the production process. We assume this recovery amounts to 100 percent of the LPGs and 60 percent of the methane recovered two years after the injection date. The cost of the injected hydrocarbons net of the present value of the amount to be recovered in the future is deductible as an operating expense in the royalty calculations.

A8) Since gas plants are assumed to be in place from the primary/-secondary operation, and since the general distribution system is assumed already in existence, no specific extra equipment is required for compressing and injecting the methane. However, some expansion of field plant capacity may be required to handle the extra hydrocarbon production.

Technical Relationships

T1) Calculation of wells required.

From A2 the implied ratio of injection wells to production wells is 0.8. This allows calculation of total wells required as production wells (WP) + injection wells (WI).

WP = total acerage ÷ pattern size
WI = 0.8 x WP

From this total we subtract the projected number of wells that will be in place following waterflood (as discussed in Section 4.4) which yields the number of new wells that must be drilled to develop this reservoir.

T2) Calculation of the number of cubic feet of methane equivalent to a reservoir barrel at given depths and temperatures

This calculation is identical to that for CO_2 given in the CO_2 model (see T3). The only difference is that the critical temperature for methane is 140.6°K and the critical pressure is 45.4 atmospheres.

Footnotes

[1] The general outlines of this model were suggested by Dr. D.L. Flock of the University of Alberta.

[2] The generalized compressibility chart used is Figure 3-2 (p. 28) of Robert C. Reid, and Thomas K. Sherwood, The Properties of Gases and Liquids: Their Estimation and Correlation, (New York: McGraw-Hill, 1977), second edition.

APPENDIX E

APPENDIX E

DETAILED SENSITIVITY ANALYSIS

E.1 Sensitivity Analysis on Costs

E.1.1 Variation of Incremental Recovery and Production Rates With Costs

Total costs of individual reservoirs were altered by ±25 percent with fairly significant results on aggregate output. Incremental recovery was reduced from the base case 2.4 billion barrels to 862 million when costs were increased across the board. A similar reduction in costs increased recovery to 2.975 billion barrels, which is 116 million barrels more than the response to a similar percentage price reduction. As in the price variations discussed above, the asymetric cost variation results reveal the large amount of marginal oil at current costs and prices.

The impact on production rates is illustrated in Figures E.1 to E.3. The impact differs by process with the chemical processes showing more response to cost reductions than the others but with the overall trend being established by the large miscible group. Overall peak production rates vary from 244 Mb/d peaking in 1991, in the high cost case, to 780 Mb/d peaking in 1992, in the low cost case.

E.1.2 Process Shares and Costs

The impact of cost variation on process shares is shown in Table E.1. Again the significant change comes between base and high cost cases. Once the marginal reservoirs are made economic, further cost reductions leave shares essentially unchanged.

TABLE E.1

PERCENTAGE SHARES BY PROCESS OF TOTAL TERTIARY PRODUCTION FOR ALTERNATE COST ASSUMPTIONS

Costs	Total Tertiary Recovery (MMbbl)	Thermal Share (%)	Chemical Share (%)	Miscible Share (%)
0.75 x base	2,976	16	8	76
Base	2,407	17	5	78
1.25 x base	862	27	11	62

FIGURE E.1

SENSITIVITY OF AGGREGATE INCREMENTAL RECOVERY TO CHANGES IN TOTAL COSTS

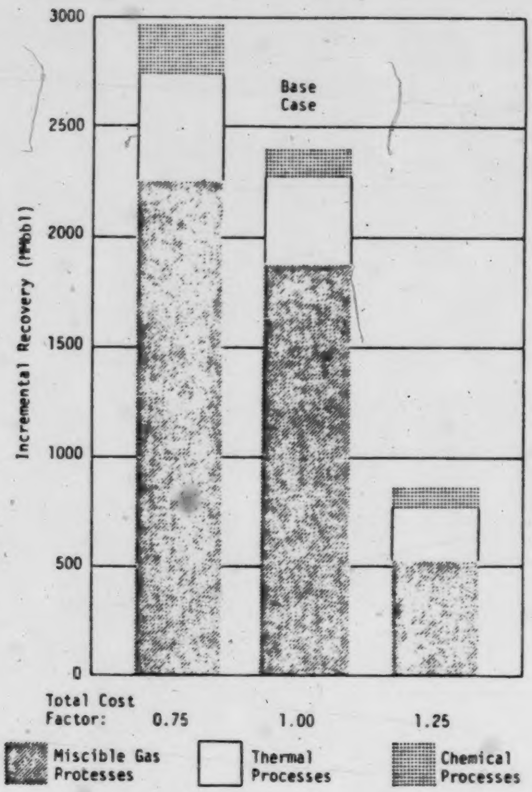


FIGURE E.2

IMPACT OF COST CASES ON PRODUCTION ALL PROCESSES

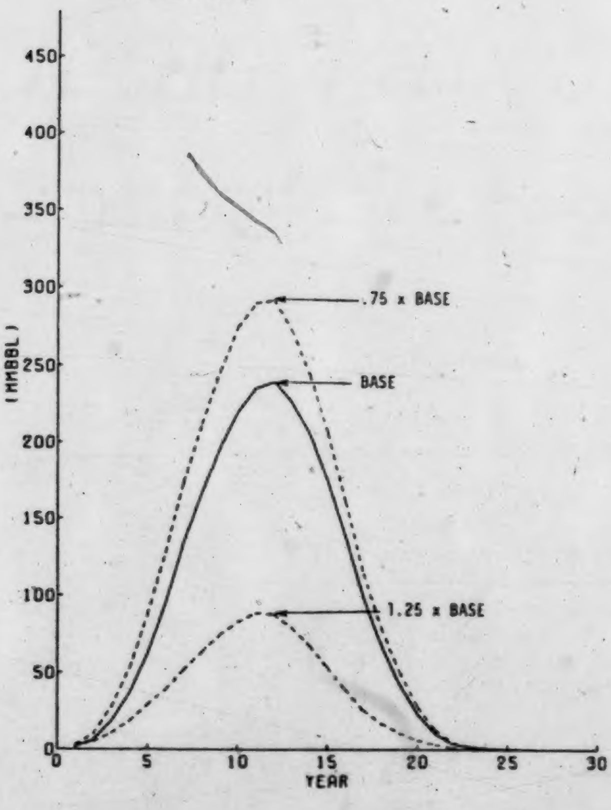
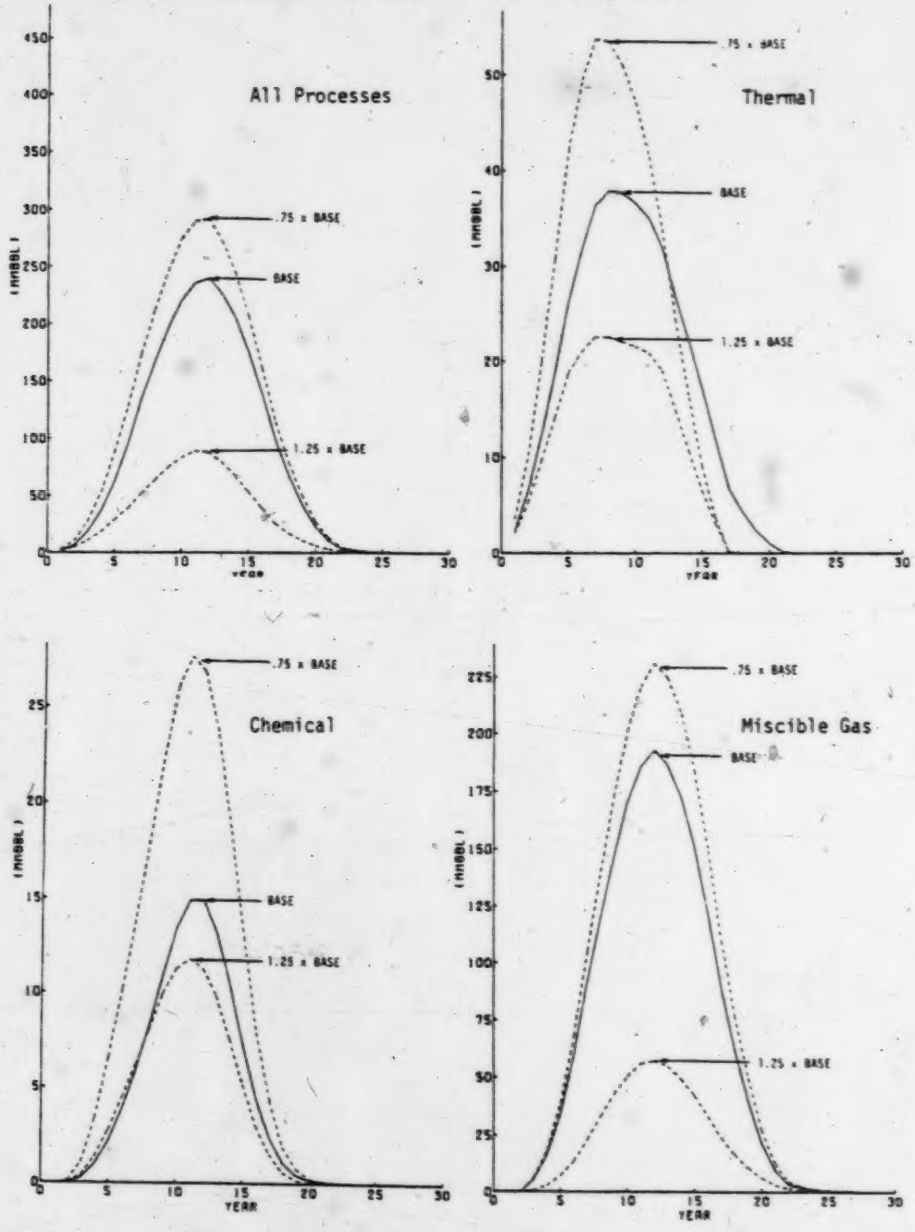


FIGURE E.3: Sensitivity of Rates of Production to Changes in Individual Reservoir Development Costs of ±25 percent of Base Case Estimates



E.1.3 The Impact of Alternate Cost Assumptions on Aggregate Costs

Alternate assumptions regarding costs of development of individual reservoirs involve two opposing impacts in the aggregate. Lower costs reduce costs for each pool but increase the number of pools thus increasing aggregate costs. Higher costs have an opposite effect. The increase in individual pool costs reduces the number of eligible pools significantly in the miscible drive group so that overall costs are reduced substantially. Similar cost increases have much less of an effect on the chemical process group. These effects are shown in Figures E.4 to E.6 and suggest again the 'hardiness' of the qualifying chemical reservoirs. The miscible group includes many quite marginal projects under base case conditions. Cost reductions have an opposite effect, increasing the chemical projects significantly. The base case conditions and the screening procedure have clearly left us with only the highest quality candidates in the chemical group.

E.1.4 Social Value and Costs

The tax impact on production for the alternate assumptions is set out in Tables E.2 and E.3. Table E.2 shows the impact on barrels produced and Table E.3 the impact on the net value of production. The tax impact is much less variable for changes in costs than changes in prices because the tax system is revenue based. The 11 billion barrels lost in the low cost case have a net value of $40 million whereas the 170 million barrels lost in the high cost case have a net social value of about $200 million (the 'cost' of the tax system).

TABLE E.2

IMPACT OF TAX SYSTEM ON RECOVERY UNDER ALTERNATE COST ASSUMPTIONS

Costs	Recovery No Tax or Royalty (MMbbl)	Recovery Current Taxes & Royalties (MMbbl)	Recovery Tax Impact (MMbbl)
0.75 x base	2,987	2,976	11
Base	2,706	2,407	299
1.25 x base	1,032	862	170

FIGURE E.4: Sensitivity of Aggregate Total Costs to Changes in Assumed Individual Reservoir Costs

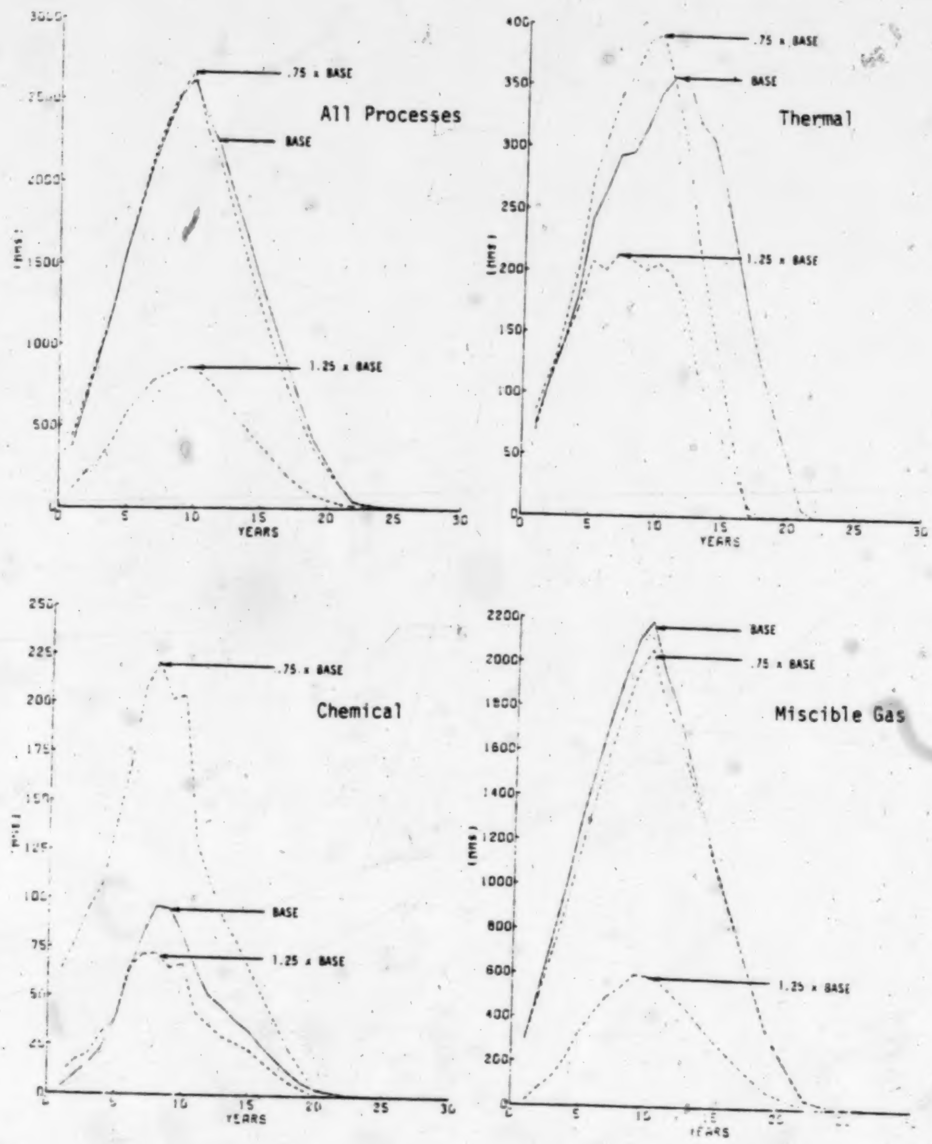
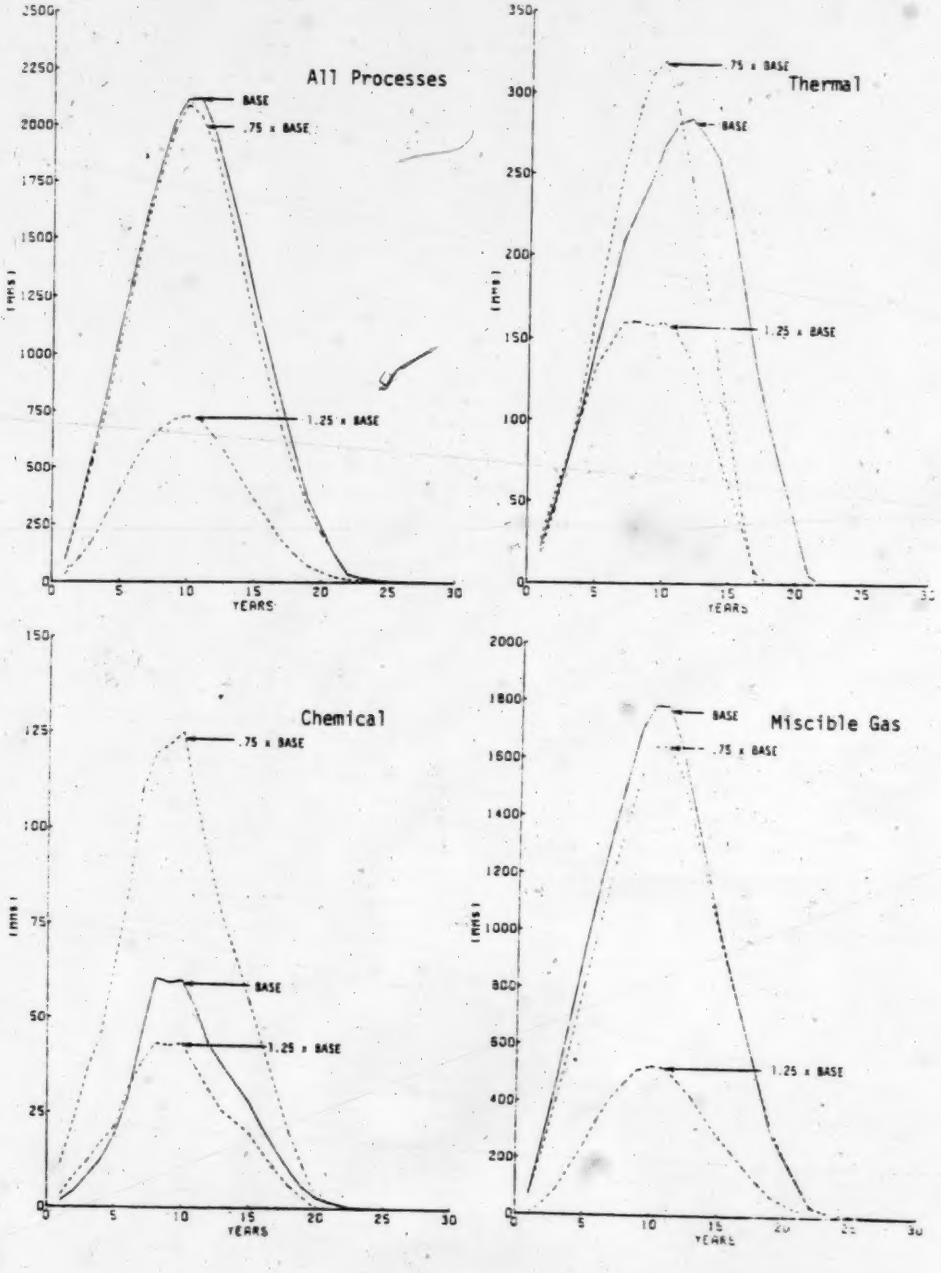


FIGURE E.5: Sensitivity of Aggregate Variable Costs (Operating Plus Materials) to Changes in Individual Costs



All Processes

Thermal

Chemical

Miscible Gas

FIGURE E.6: Sensitivity of Aggregate Capital (Fixed) Costs to Changes in Individual Costs

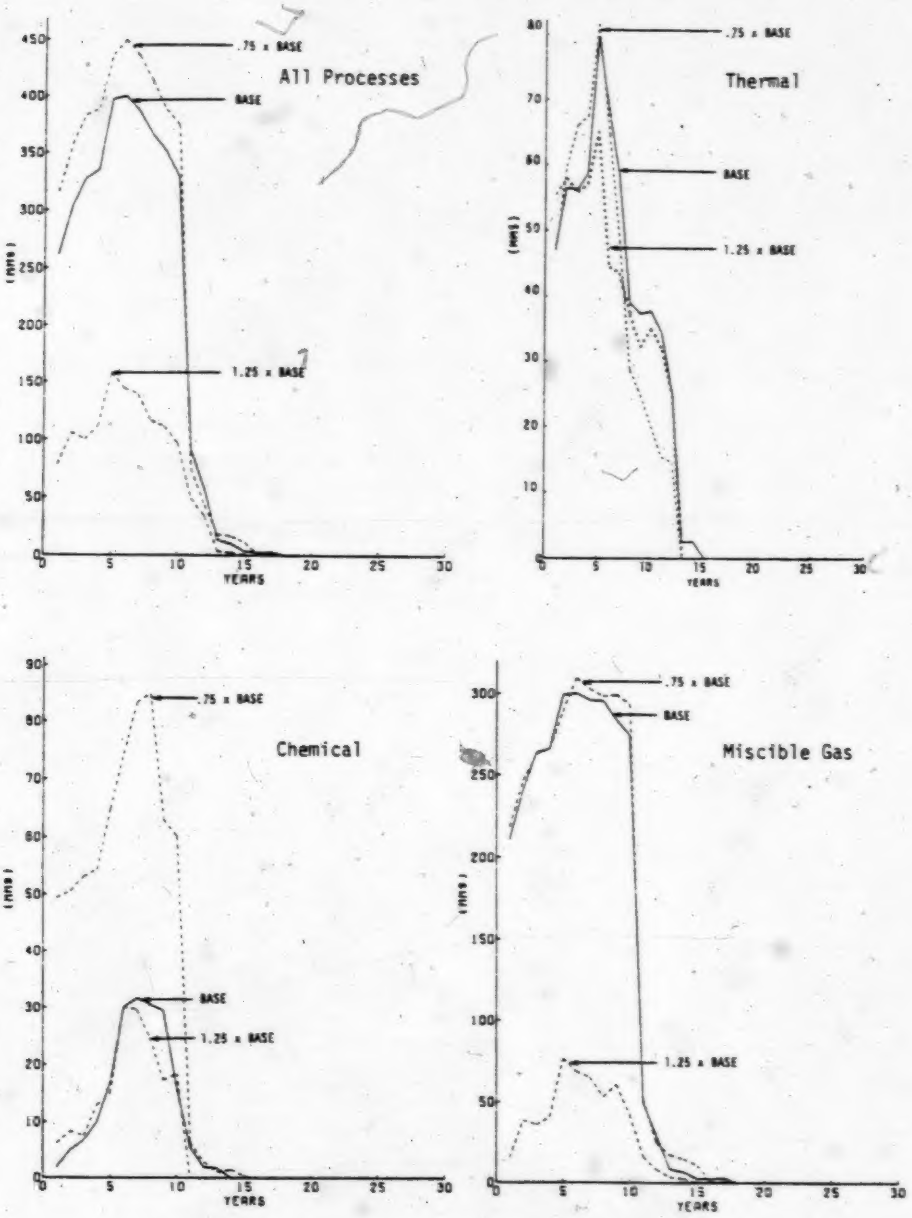


TABLE E.3

POTENTIAL AND REALIZED SOCIAL VALUE UNDER ALTERNATE COST ASSUMPTIONS

	Potential Net Social Value ($billion)	Realized Net Social Value ($billion)	Change in Net Social Value Attributable to the Impact of the Tax System ($billion)
0.75 x base	13.07	13.0	0.04
Base	7.4	7.0	0.4
1.25 x base	3.5	3.3	0.2

Again the tax system has its most adverse effect in the base case, 229 million barrels, representing $400 million net loss to society.

E.1.5 Revenue Shares and Costs

The division of net revenues under alternate cost regimes stays relatively constant, about two-thirds to one-third in favour of government, as shown in Table E.4.

TABLE E.4

DIVISION OF NET REVENUES BETWEEN INDUSTRY AND GOVERNMENT

	Total Net Revenue ($MM)	After Tax Net Revenue ($MM)	% of Total	Tax Take ($MM)	% of Total
0.75 x base	13,027	5,039	39	7,988	61
Base	7,005	2,450	35	4,555	65
1.25 x base	3,335	1,335	40	2,000	60

E.1.6 Impact of Cost Variations on Economic Results

The impact of alternate cost assumptions is detailed in Table E.5. Recovery varies inversely with costs as would be expected, and again the movement from base to high cost scenarios knocks a lot of marginal reservoirs out of contention. This effect is most pronounced for the miscible processes in which base case recovery is reduced by 72 percent when higher costs are imposed.

TABLE E.5

ECONOMIC RESULTS OF COST SENSITIVITY ANALYSIS

	Present Value				
	Net Revenue ($MM)	Taxes & Royalties ($MM)	Supply Price ($)	Internal Rate of Return (%)	Forecast Incremental Recovery (MMbbl)
All Processes					
TC = 0.75 x base	5,039	7,988	11.00	27	2,976
TC = base	2,450	4,555	13.90	17	2,407
TC = 1.25 x base	1,335	2,000	12.30	27	862
Thermal					
TC = 0.75 x base	1,324	2,415	7.58	664	491
TC = base	756	1,435	10.50	131	407
TC = 1.25 x base	545	739	10.90	69	236
Chemical					
TC = 0.75 x base	414	602	11.10	21	228
TC = base	255	422	7.90	37	115
TC = 1.25 x base	216	368	8.00	34	96
Miscible					
TC = 0.75 x base	3,301	4,971	12.00	21	2,256
TC = base	1,439	2,698	15.20	13	1,885
TC = 1.25 x base	574	893	13.90	17	530

The internal rate of return again varies in an unpredictable fashion but now the supply price also moves erratically. Although increasing individual pool costs act to increase the supply price, in the aggregate the increased costs eliminate some less productive reservoirs and this influence is enough to reduce the aggregate supply price below what it is in the base case. Supply prices vary with the discount rate as well and this relationship is illustrated for each process group in Figure E.7. Unlike the result in the price variation discussion, the supply prices lines here actually cross at a sufficiently high discount rate. This suggests one or both of two possibilities: (1) the low cost scenario involves a higher concentration of costs in the earlier years that are affected to a greater degree by larger discount rates; and (2) the low cost involves a higher concentration of production in earlier years which is affected somewhat more by the discounting process.

The present value measures vary reliably in an inverse relation with pool costs and here an interesting fact may be noted. Lower costs increase recovery by 24 percent but increase net revenue by 86 percent. The net value is increased not only by increasing viable reservoirs but also by increasing the net profit of all reservoirs. Higher costs reduce recovery by 64 percent but net value is reduced by only 52 percent. Effects opposite to those above are somewhat ameliorated by the elimination of the higher cost reservoirs from the profitable set.

Variance of social value and industry profit with costs also depends on the discount rates applied as shown by Figures E.8 and E.9.

E.1.7 Impact of Increasing Individual Cost Components

In addition to carrying out sensitivity analysis on total costs we looked at the impact of increasing individual cost components (capital, operating and materials). Each cost category was increased by 25 percent while holding other cost categories at base case levels. The purpose was to investigate the relative importance of the various cost categories in a 'worst case' situation.

The effect of this on incremental recovery is shown in Table E.6. The thermal processes are least sensitive to capital cost increases which reduce recovery by 24 percent. They are equally sensitive to increases in operating and material costs which reduce recovery by 35 percent. The chemical processes show almost no sensitivity to capital cost increases and only slightly more reaction to material and operating cost increases which reduce recovery by 4 and 8 percent respectively. The miscible processes respond about equally to capital and operating cost increases; recovery being reduced by 18 and 20 percent. They are, however, extremely sensitive to materials cost increases, reducing recovery by 64 percent which is only 8 percent less than the reduction in recovery attendant on similar increases in total costs. The aggregate results are again dominated by the miscible group. Increasing capital costs reduces overall recovery by 18 percent, operating costs have a 22 percent impact and materials costs a

FIGURE E.7: Variation of Supply Price with Discount Rate for Alternate Cost Cases

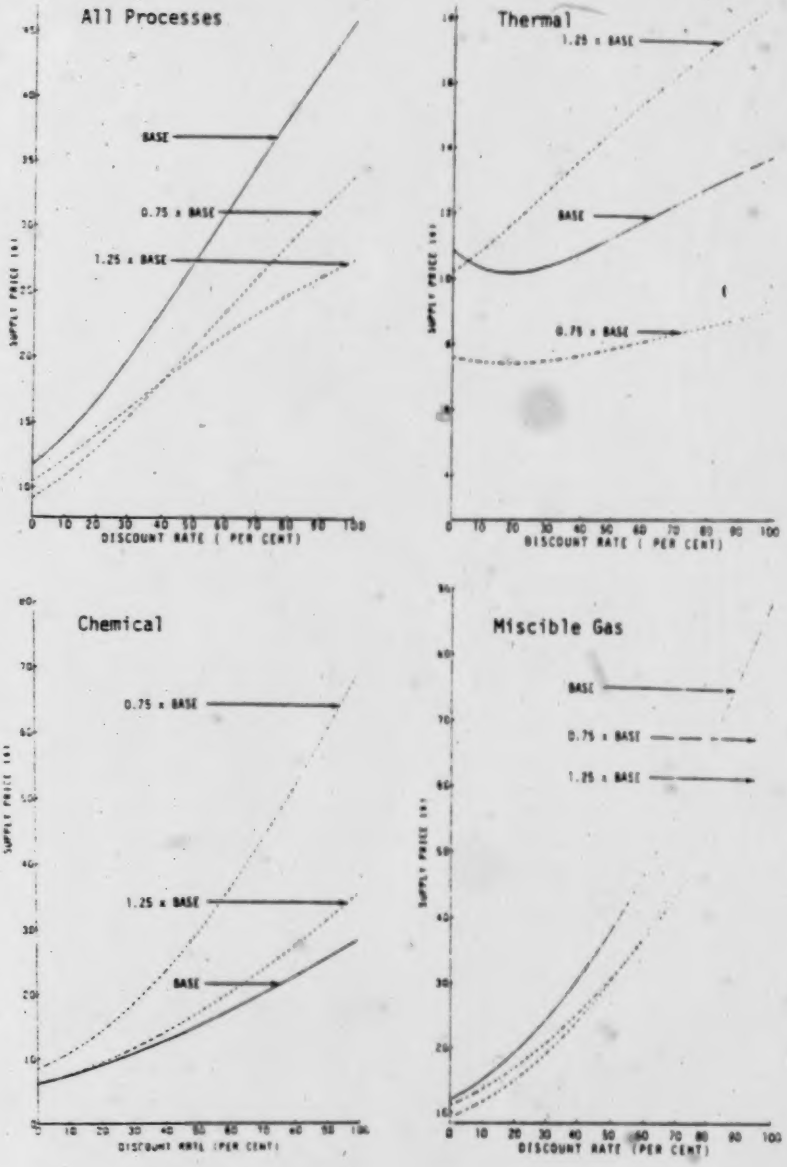


FIGURE E.8

VARIATION OF REALIZED SOCIAL VALUE FROM ENHANCED RECOVERY WITH DISCOUNT RATES UNDER ALTERNATE COST ASSUMPTIONS

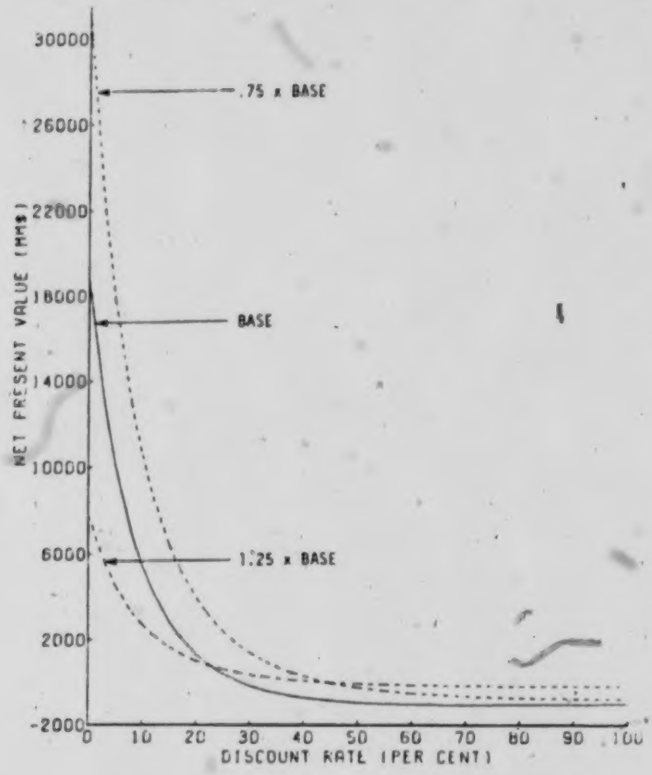
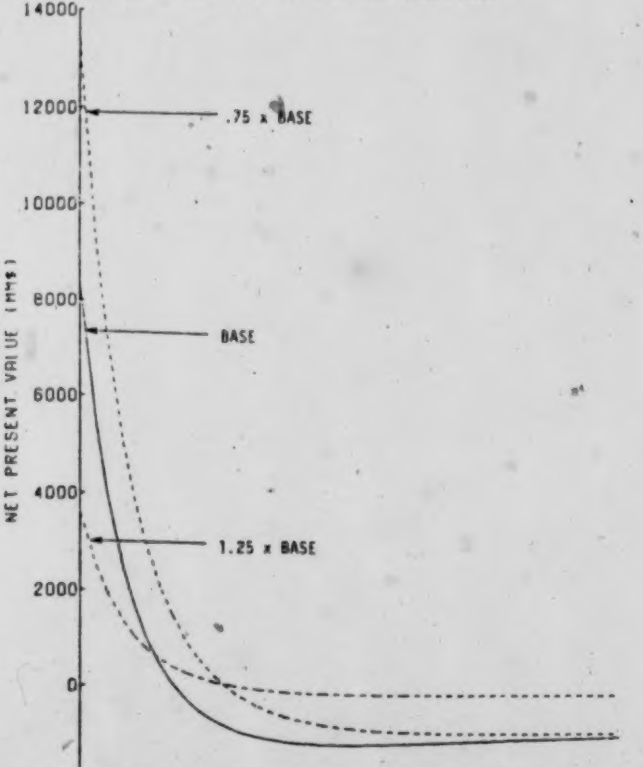


FIGURE E.9

VARIATION OF INDUSTRY AFTER TAX NET REVENUE WITH DISCOUNT RATES UNDER ALTERNATE COST ASSUMPTIONS



57 percent impact. These results may be compared with the reduction of 64 percent of base case recovery that occurs when total costs are increased by 25 percent.

TABLE E.6

COST SENSITIVITY RESULTS ON INCREMENTAL RECOVERY
(MMbbl)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Total Cost				
0.75 x base	2,976	491	228	2,256
base	2,407	407	115	1,885
1.25 x base	862	236	96	530
Capital Cost				
base	2,407	407	115	1,885
1.25 x base	1,962	310	114	1,538
Operating Cost				
base	2,407	407	115	1,885
1.25 x base	1,878	264	106	1,508
Materials Cost				
base	2,407	407	115	1,885
1.25 x base	1,047	264	110	673

Process shares are not materially affected by increases in capital or operating costs but increases in materials costs reduce the miscible share to 64 percent as shown in Table E.7. This procedure did not allow for the possibility of individual materials costs being higher than others. For example, costs of carbon dioxide might be higher than estimates used here, whereas our chemical costs are good approximations. In that case, the reduction in miscible share would be even more than shown.

TABLE E.7

EFFECT ON PROCESS SHARES OF INCREASING INDIVIDUAL COST COMPONENTS

All Processes	Total Tertiary Recovery (MMbbl)	Thermal Share (%)	Chemical Share (%)	Miscible Share (%)
Base case	2,407	17	5	78
TC = 1.25 x base	862	27	11	62
CC = 1.25 x base	1,962	16	6	78
OC = 1.25 x base	1,878	14	6	80
CM = 1.25 x base	1,047	25	11	64

Since cost changes pull in two directions, little significance can be attached to changes in either supply prices or internal rates of return which, in any case, were not affected materially by changes in components of costs. The impact on net social value and its division between industry and government is given in Table E.8. Total net social value is reduced by 16, 27 and 42 percent, respectively, by increases in capital, operating, and materials costs. This may be compared with the 52 percent reduction when total costs are increased. The division of revenues is not affected, however. Governments consistently capture only 60 to 65 percent of the total value through taxes and royalties.

TABLE E.8

EFFECT ON REVENUE SHARES OF CHANGES IN COST ASSUMPTIONS

		Present Value			
All Processes	Total Social Value	Company Net Revenue	% of Total	Taxes & Royalties	% of Total
Base case	7,005	2,450	35	4,555	65
TC = 1.25 x base	3,335	1,335	40	2,000	60
CC = 1.25 x base	5,861	2,130	36	3,731	64
OC = 1.25 x base	5,129	1,771	35	3,358	65
CM = 1.25 x base	4,101	1,625	40	2,476	60

E.2 Sensitivity Analysis on Pattern Size

Pattern size refers to the number of acres serviced by an individual pattern, in most cases here a five spot. It is a parameter of technical importance to reservoir engineers since it affects the timing and effectiveness of the development process. We considered patterns one half and two times the base case in size. This is assumed not to alter the effectiveness of the particular process in the sense that incremental recovery in a given reservoir does not change with increased or reduced pattern size. The effect is primarily on costs through changes in wells required and associated equipment. Using 10 acre five spots in the steam drive process instead of 5 acre five spots would reduce the total number of wells required to develop the reservoir. In some cases the impact of a change in the pattern size would be partially offset by an opposite impact on the flow check well requirement. For example, increasing the pattern size thus reducing the well requirements might increase the implied flow rate beyond the reservoir's theoretical limit. Thus the flow check would become operative and increase the number of wells required. The variations in pattern size by process are set out in Table E.9.

TABLE E.9

VARIATIONS ON PATTERN SIZE ASSUMPTION

	Pattern	Base Size (acres)	0.5 x Base High Cost (acres)	2 x Base Low Cost (acres)
Steam drive	5-spot	5	2.5	10
Steam stimulation	-	5	2.5	10
In situ combustion	9-spot	20	10	40
Polymer augmented waterflood	5-spot	80	40	160
Alkaline flood	5-spot	40	20	80
Microemulsion flood	5-spot	20	10	40
CO_2 miscible				
(sandstones)	5-spot	80	40	160
(carbonates)	5-spot	80	40	160
Hydrocarbon miscible (sandstones and carbonates	5-spot	80	40	160

E.2.1 Variation of Incremental Recovery and Production Rates With Pattern Size

Table E.10 and Figures E.10 to E.12 show the impact of pattern size variation on incremental recovery and production rates. The overall impact is similar to that of total cost variation though reductions in production are more pronounced. The chemical and miscible processes are quite sensitive to the cost change associated with reduced pattern size. Production declines of 46 and 81 percent result. However, the thermal group responds perversely. The reduced pattern size actually increases recovery by about 3 million barrels. The change occurs in the in situ group where, in spite of a reduction in eligible reservoirs from 38 to 31, recoverable oil goes up. The new pattern of costs interacts with the tax and discounting procedures in such a way as to make some of the larger marginal reservoirs dominant and profitable.

TABLE E.10

PATTERN SIZE AND INCREMENTAL RECOVERY
(MMbbl)

Pattern Size	All Processes	Thermal	Chemical	Miscible
0.5 x base	821	410	62	349
Base	2.407	407	115	1,885
2 x base	2,944	456	231	2,257

E.2.2 Process Shares and Pattern Size

The impact on shares of recovery by process group is given in Table E.11. The only notable change occurs because of the reaction of the thermal group which causes its share to increase from 17 to 50 percent.

TABLE E.11

PERCENTAGE SHARES BY PROCESS OF TOTAL TERTIARY
PRODUCTION FOR ALTERNATE PATTERN SIZE ASSUMPTIONS

Pattern Size	Total Tertiary Recovery (MMbbl)	Thermal Share (%)	Chemical Share (%)	Miscible Share (%)
0.5 x base	821	50	8	42
Base	2,407	17	5	78
2 x base	2,944	15	8	77

FIGURE E.10

SENSITIVITY OF AGGREGATE INCREMENTAL RECOVERY TO CHANGES IN PATTERN SIZE

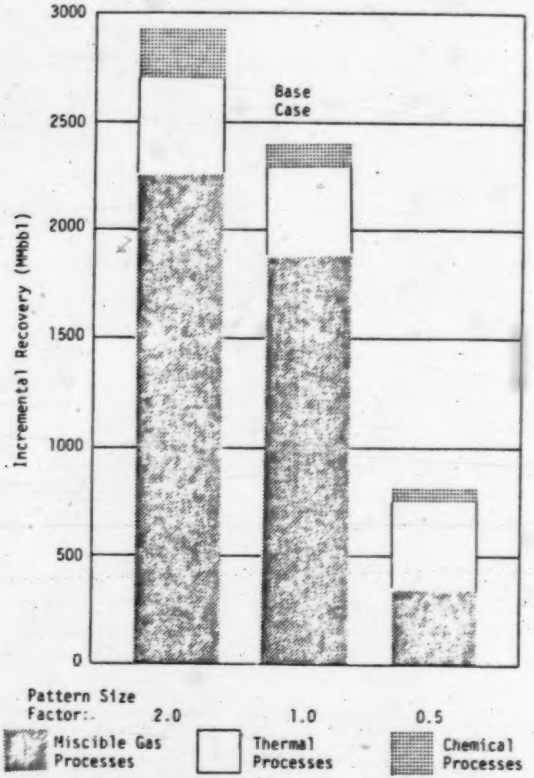


FIGURE E.11

SENSITIVITY OF YEARLY PRODUCTION RATES TO CHANGES IN ASSUMED PATTERN SIZE, ALL PROCESSES

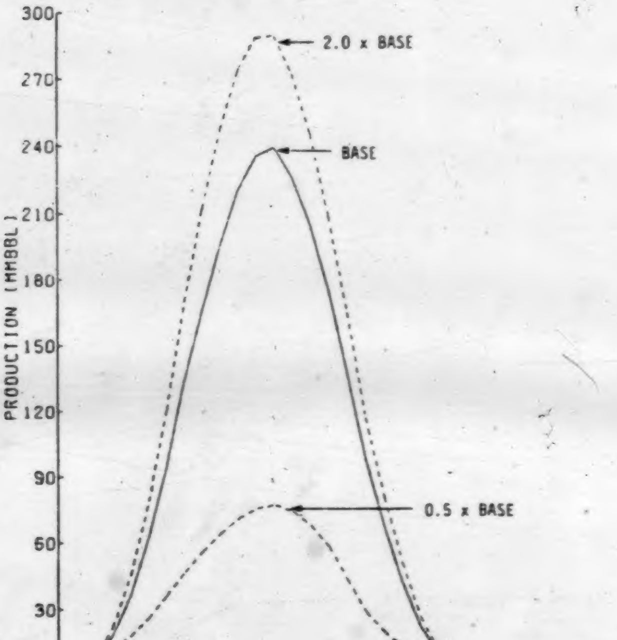
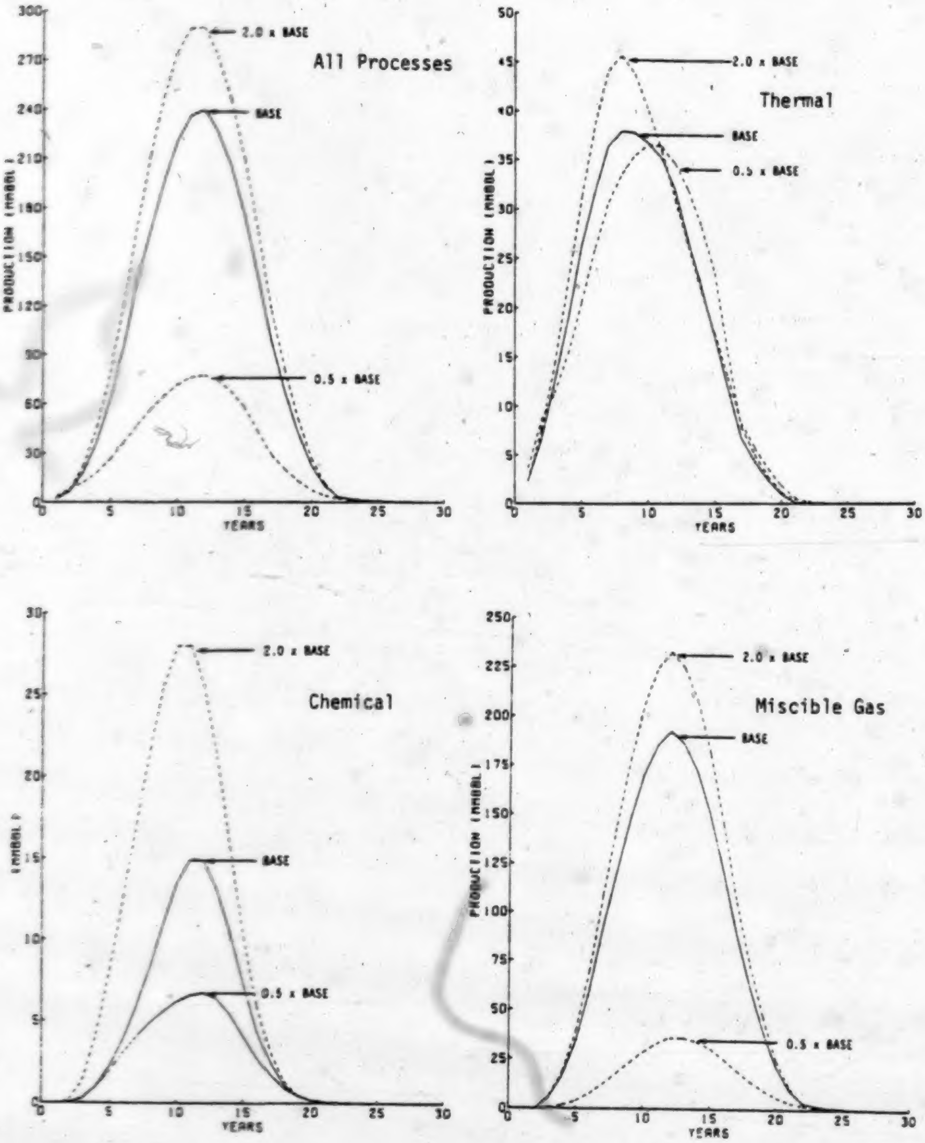


FIGURE E.12: Sensitivity of Yearly Production Rates to Changes in Assumed Pattern Size



E.2.3 Pattern Size and Costs

Changing pattern size affects costs in several ways. Reducing pattern size, for example, increases wells required and therefore capital costs. This may be partially offset by an elimination of any extra wells that might have been required with a larger pattern size due to the flow check. In the aggregate, increased individual reservoir costs eliminate many reservoirs from the profitable set thus overall costs are reduced. The overall impact on cost flows is illustrated in Figures E.13 to E.15.

The chemical and thermal processes are significantly affected by both increases and reductions in pattern size, whereas the impact on the miscible process is only notable when pattern size is cut in half, reducing the number of reservoirs and thus aggregate costs.

Since the miscible processes outweigh the others by a considerable margin, the sensitivity of all processes together follows closely that of the miscible group. An increase in pattern size has little effect on this group because the wells assumed in place from waterflooding on 80 acre spacing mean that with miscible also on 80 acre spacing not much drilling is required. Doubling the spacing reduces wells required by very little, whereas halving the spacing to 40 acres significantly increases required drilling and therefore costs.

E.2.4 Social Value and Pattern Size

Table E.12 sets out the potential and realized social value of tertiary recovery. Figure E.16 illustrates how realized social value at various discount rates varies for alternate pattern size assumptions. The variation is quite large and, interestingly, net value remains positive for higher discount rates in the small pattern size (high cost) case than in the others. Another quirk of timing of the flows of costs and revenues.

TABLE E.12

POTENTIAL AND REALIZED SOCIAL VALUE UNDER ALTERNATE PATTERN SIZE ASSUMPTIONS

	Potential Net Social Value ($billion)	Realized Net Social Value ($billion)	Change in Net Social Value Attributable to the Impact of the Tax System ($billion)
0.5 x base	3.1	2.9	0.2
Base	7.4	7.0	0.4
2 x base	12.4	12.0	0.4

FIGURE E.13: Sensitivity of Aggregate Total Costs to Changes in Assumed Pattern Size

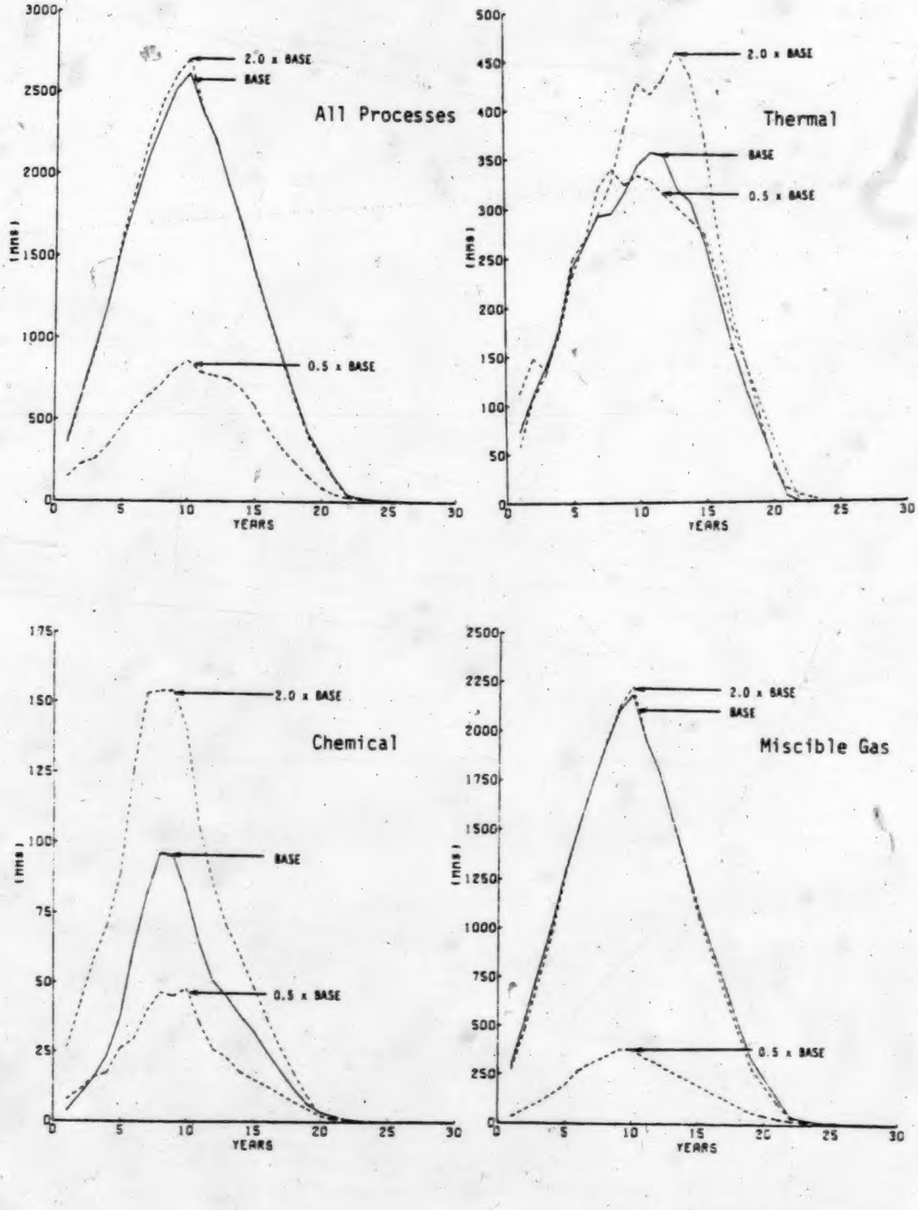


FIGURE E.14: Sensitivity of Aggregate Variable Costs (Operating Plus Materials) to Changes in Individual Costs

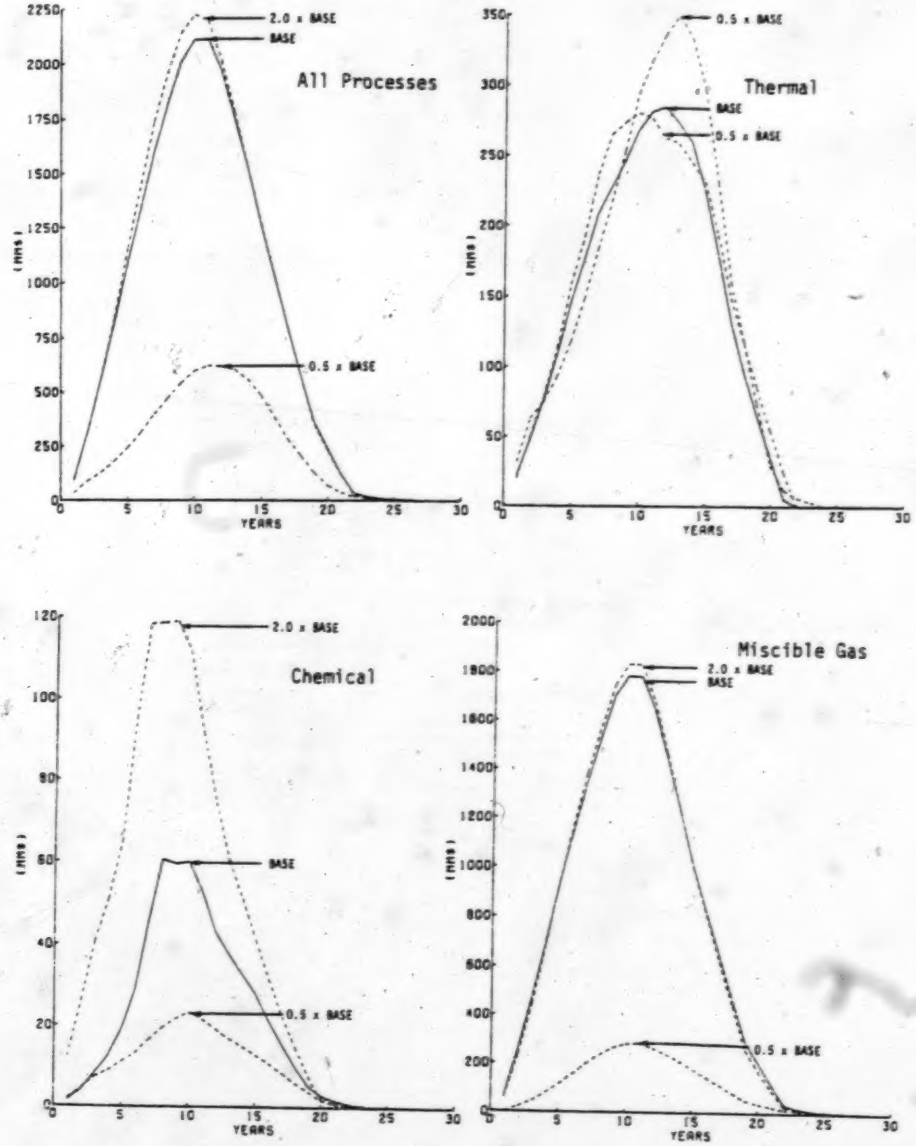
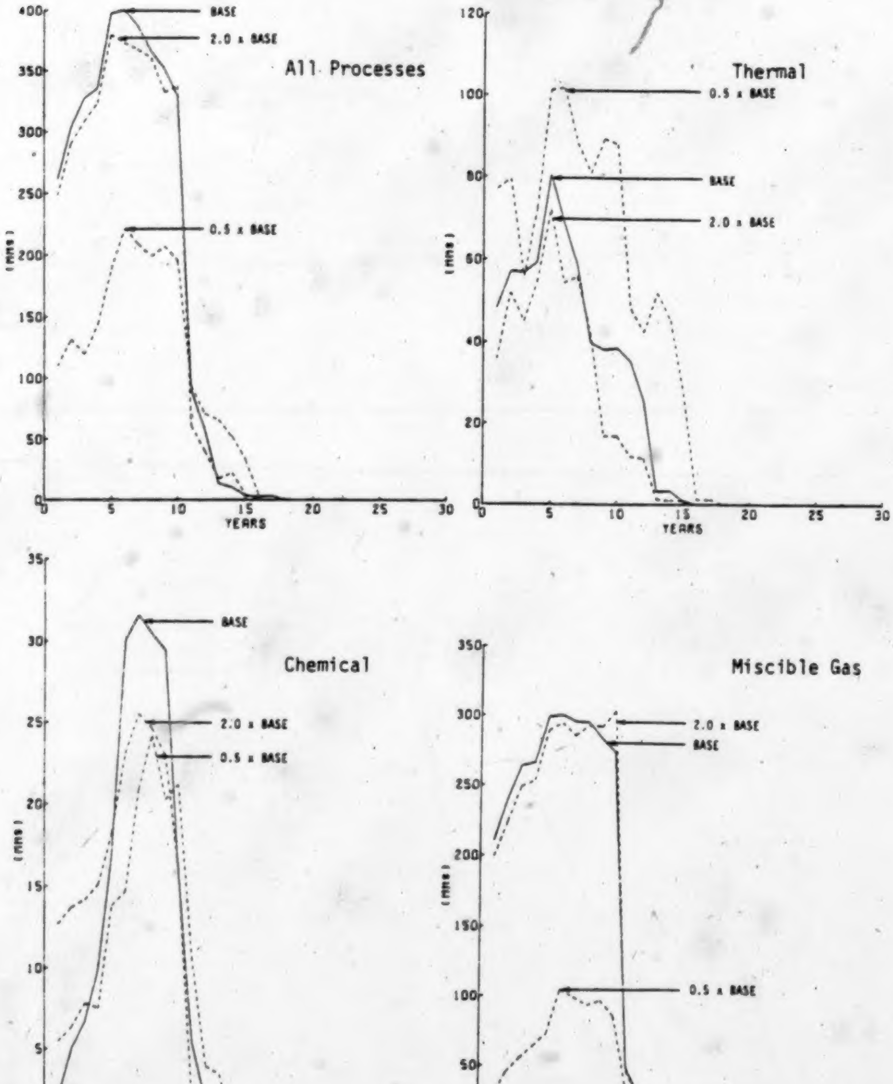


FIGURE E.15: Sensitivity of Aggregate Capital (Fixed) Costs to Changes in Pattern Size



E.2.5 General Impact of Pattern Size Variation on Economic Results

The division of the realized net social value between governments and industry is presented in Table E.13. Revenue shares remain relatively constant with industry retaining 35 percent of the economic rent. The value of production after taxes (producer's share) is presented in Figure E.17. Comparison with Figure E.16 indicates that the tax system appears to reduce the variation in value associated with different pattern size assumptions.

Supply prices versus discount rates are plotted in Figure E.18 for alternate pattern size assumptions. The 'high cost' assumption implies a flow of costs per barrel which is relatively insensitive to the discount rate in the aggregate.

E.3 Sensitivity Analysis on Recovery Factor Assumptions

The recovery factor is established for each reservoir by the formula

$$RF = \frac{S_{orw} - S_{ort}}{S_{orw}} .$$

It is therefore unique to each reservoir and once established we multiply it by ultimate remaining oil in place to estimate incremental recovery. The sensitivity analysis operates on RF, varying it by 0.85, 0.90, and 1.15. This means that aggregate recovery is affected directly by whatever factor is used but also indirectly in that, for example, reducing RF in any individual reservoir may make that project unprofitable so that recovery is reduced by its entire potential production not merely a portion of it.

Again, however, our flow check complicates the impact. If we increase RF by 15 percent we may increase the rate of production implied by our set of production assumptions. If the increase is enough to surpass the maximum theoretical production rate as established by reservoir parameters, extra drilling would be triggered, the increased costs of which might make the project unprofitable. This possibility is unlikely to affect already profitable reservoirs since the increased revenue is sure to outweigh the increased costs. However, some marginally unprofitable reservoirs which might have been made profitable by the increased recovery could be prevented from this by the increased costs.

E.3.1 Variation of Incremental Recovery and Production Rates With Individual Recovery Factors

Incremental recovery factors were altered by ±15 percent (1.15 and 0.85 times base) and one additional run with them set at -10 percent was also performed. The purpose of the latter experiment was

TABLE E.13

ECONOMIC RESULTS OF PATTERN SIZE SENSITIVITY ANALYSIS

	Present Value				
	Net Revenue ($MM)	Taxes & Royalties ($MM)	Supply Price ($)	Internal Rate of Return (%)	Forecast Incremental Recovery (MMbbl)
All Processes					
PS = 1/2 x base	1,004	1,852	13.00	27	821
PS = base	2,450	4,555	13.90	17	2,407
PS = 2 x base	4,449	7,649	11.50	25	2,944
Thermal					
PS = 1/2 x base	561	1,087	12.60	88	410
PS = base	756	1,435	10.50	131	407
PS = 2 x base	900	1,886	9.30	225	456
Chemical					
PS = 1/2 x base	142	221	8.20	34	62
PS = base	255	422	7.90	37	115
PS = 2 x base	615	912	7.30	44	231
Miscible					
PS = 1/2 x base	301	544	14.40	14	349
PS = base	1,439	2,698	15.20	13	1,885
PS = 2 x base	2,934	4,851	12.50	20	2,257

FIGURE E.16

VARIATION OF REALIZED SOCIAL VALUE FROM ENHANCED RECOVERY WITH ASSUMED DISCOUNT RATES UNDER ALTERNATE PATTERN SIZE ASSUMPTIONS, ALL PROCESSES

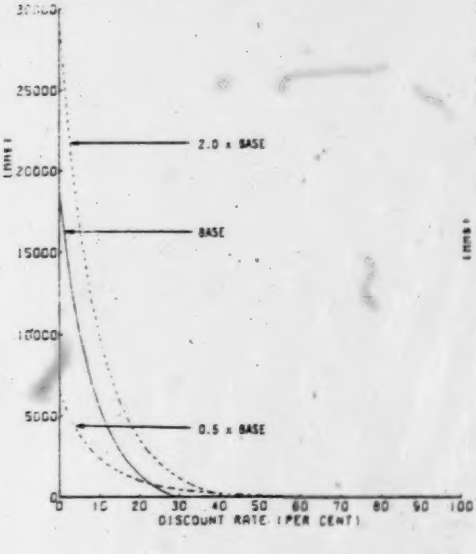


FIGURE E.17

VARIATION OF INDUSTRY AFTER TAX NET REVENUE WITH DISCOUNT RATES UNDER ALTERNATE COST ASSUMPTIONS, ALL PROCESSES

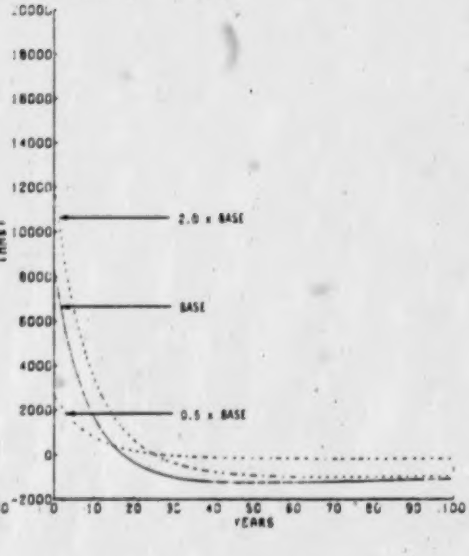
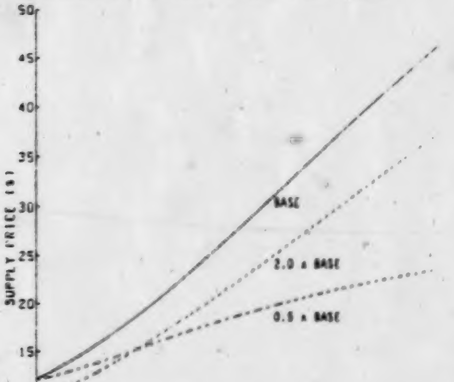


FIGURE E.18

VARIATION OF SUPPLY PRICE WITH ASSUMED DISCOUNT RATE FOR ALTERNATE PATTERN SIZE ASSUMPTIONS, ALL PROCESSES



to see if we could break through the bubble of marginal reservoirs with a slightly improved recovery assumption. This turned out to be the case as shown by Figures E.19 and E.20. Using 0.85 of the recovery factor reduced ultimate production by 1.6 billion barrels (67 percent of base case recovery). Using 0.9 of the recovery factor reduced it by only 0.7 billion barrels (28 percent). This provides further evidence of the marginal nature of many pools included in our base case. The downside potential is quite high if any of our assumptions regarding price, costs, or recovery turn out to be optimistic.

The upside potential is not nearly as high. In the price variation case we noted a 25 percent increase in price would increase ultimate production by only 0.45 billion barrels or 19 percent. Cost reductions of 25 percent would increase production by 0.57 billion barrels (24 percent). Doubling the pattern size assumption also reduces costs and increases recovery by 0.54 billion barrels (22 percent). Only in the case of variance in the recovery factor does the upside potential approach the significance of the downside potential. A 15 percent increase in individual recovery factors increases ultimate production by 0.9 billion barrels, 38 perent of base case recovery.[1]

The impact of the recovery assumptions on production rates is illustrated in Figure E.21. The chemical process shows the greatest proportional increase and the smallest decrease in response to the high and low assumptions. The thermal processes show a much more symmetrical response to the changes whereas the miscible processes show a greater response on the downside than the upside. The overall results are conditioned by the miscible process which causes a larger reduction (65 percent) in response to reduced recovery factors than it does an increase in response to increased recovery factors (34 percent).

E.3.2 Process Shares and Recovery

The impact of varying the recovery factor on the percentage share of individual process groups is shown in Table E.14. A significant impact on process shares is evident only in the move from 0.85 to 0.9 suggesting that once the marginal reservoir bubble is brought on stream shares are relatively insensitive to changing assumptions.

FIGURE E.19

SENSITIVITY OF AGGREGATE INCREMENTAL RECOVERY TO CHANGES IN RECOVERY FACTORS CALCULATED FOR INDIVIDUAL RESERVOIRS

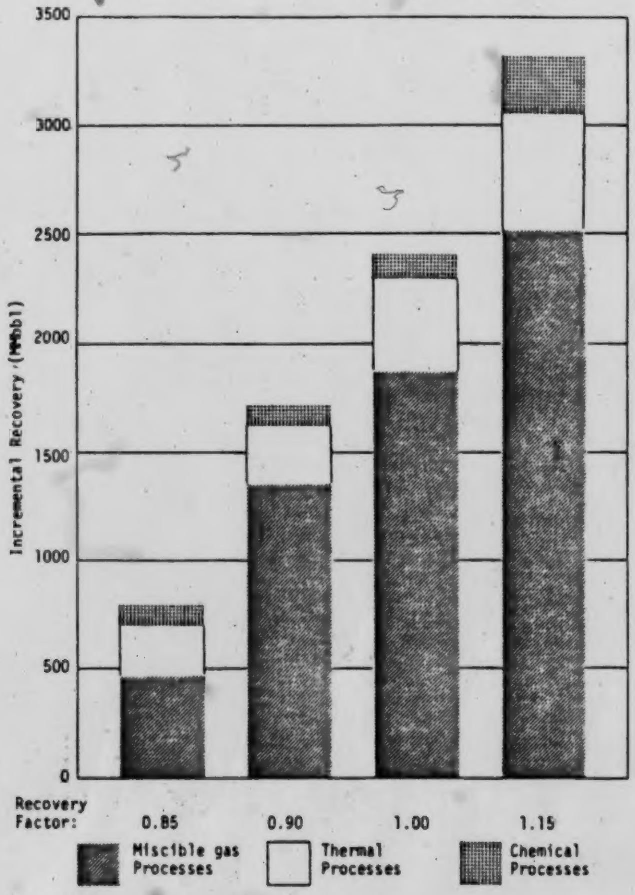


FIGURE E.20

SENSITIVITY OF YEARLY PRODUCTION TO CHANGES IN RECOVERY FACTORS CALCULATED FOR INDIVIDUAL RESERVOIRS

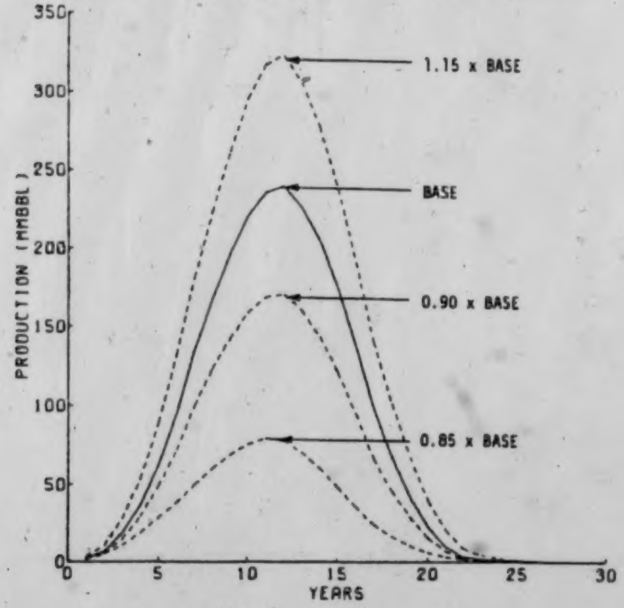


FIGURE E.21: Sensitivity of Yearly Production to Changes in Recovery Factors Calculated for Individual Reservoirs

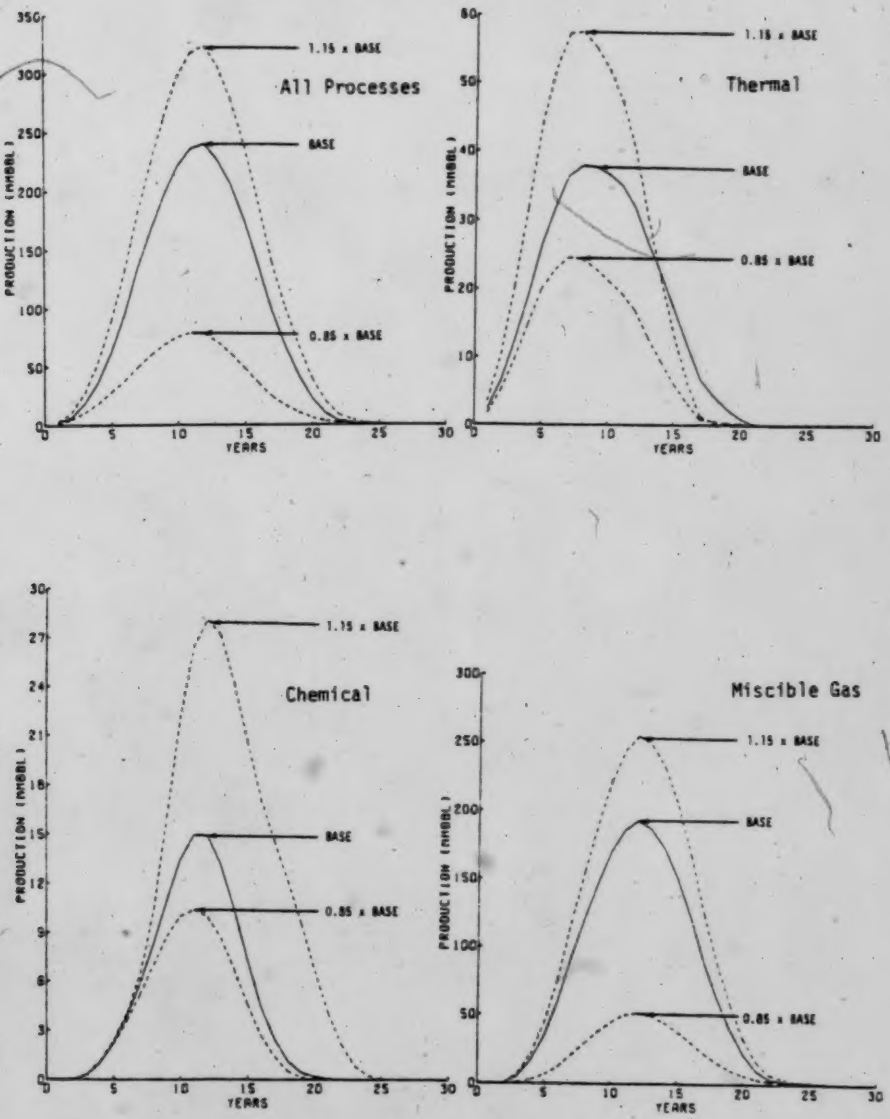


TABLE E.14

PERCENTAGE SHARES BY PROCESS OF TOTAL TERTIARY PRODUCTION FOR ALTERNATE RECOVERY FACTOR ASSUMPTIONS

Recovery Factor	Total Tertiary Recovery (MMbbl)	Thermal Share (%)	Chemical Share (%)	Miscible Share (%)
0.85 x base	796	30	10	60
0.90 x base	1,725	15	6	79
Base	2,407	17	5	78
1.15 x base	3,321	16	8	76

E.3.3 The Impact of Alternate Recovery Assumptions on Aggregate Costs

Changing the recovery assumption affects aggregate costs primarily by affecting the number of reservoirs that are profitable. There is also a potential, though minor, impact through the flow check. However, the flow check was not operative in any more cases when RF = 1.15 than it was when RF = 1. Thus it had no impact, even on marginal reservoirs once the high productivity assumption was implemented. Moreover, the number of profitable reservoirs with increased recovery under base case economic assumptions increased by 49.

The effect on cost flows is presented in Figures E.22 to E.24. Once again the opposite results on chemical and miscible processes is evident with thermal results being rather similar for increases and decreases in individual recovery factors. The results for all processes follow those of the miscible group quite closely.

E.3.4 Social Value and Alternate Recovery Factors

The direct impact of the tax system on production under alternate recovery assumptions is given in Table E.15. Table E.16 shows the change in the net value of this production. The billion barrels eliminated by the current tax collection procedure is very high cost oil with a net social value of about $300 million. This may be compared with the tax impact under high recovery which is one-twenty sixth in terms of barrels but only one-third in terms of dollars. Once again the net cost of the tax system is highest in the base case.

FIGURE E.22: Sensitivity of Aggregate Total Costs to Changes in Recovery Factors Calculated for Individual Reservoirs

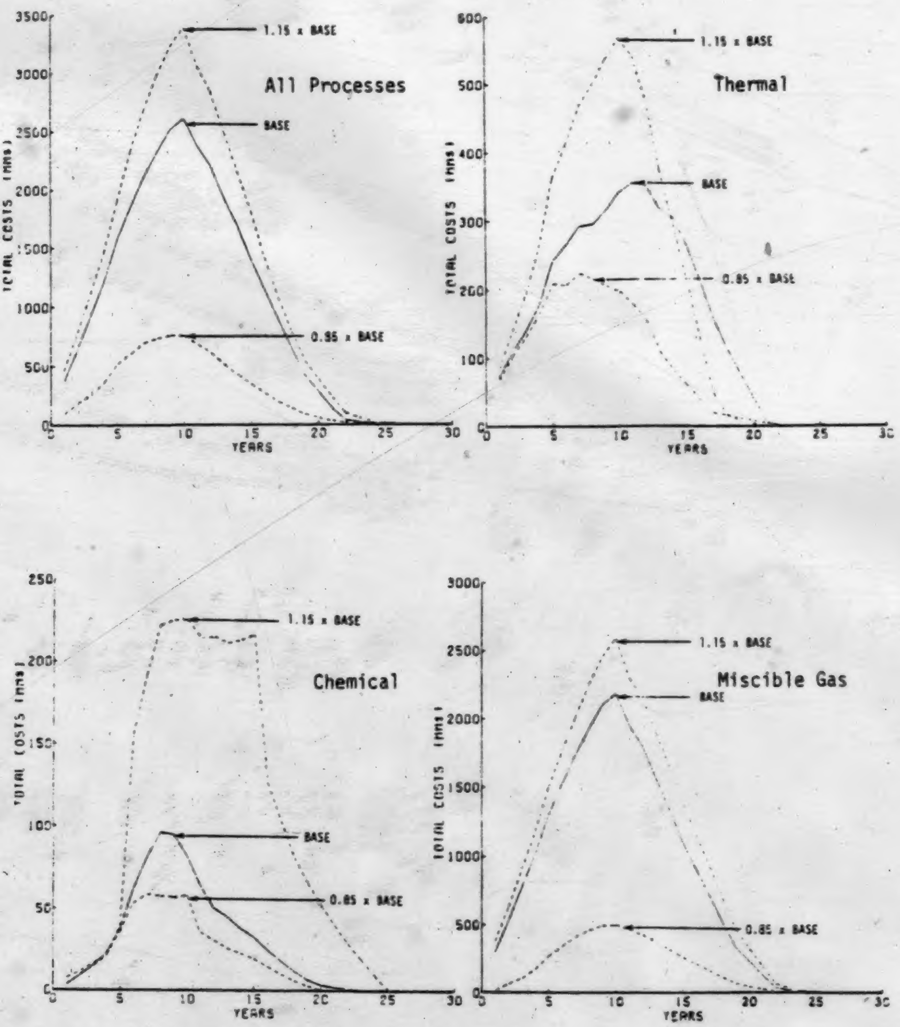


FIGURE E.23: Sensitivity of Aggregate Variable Costs (Operating Plus Materials) to Changes in Recovery Factors Calculated for Individual Reservoirs

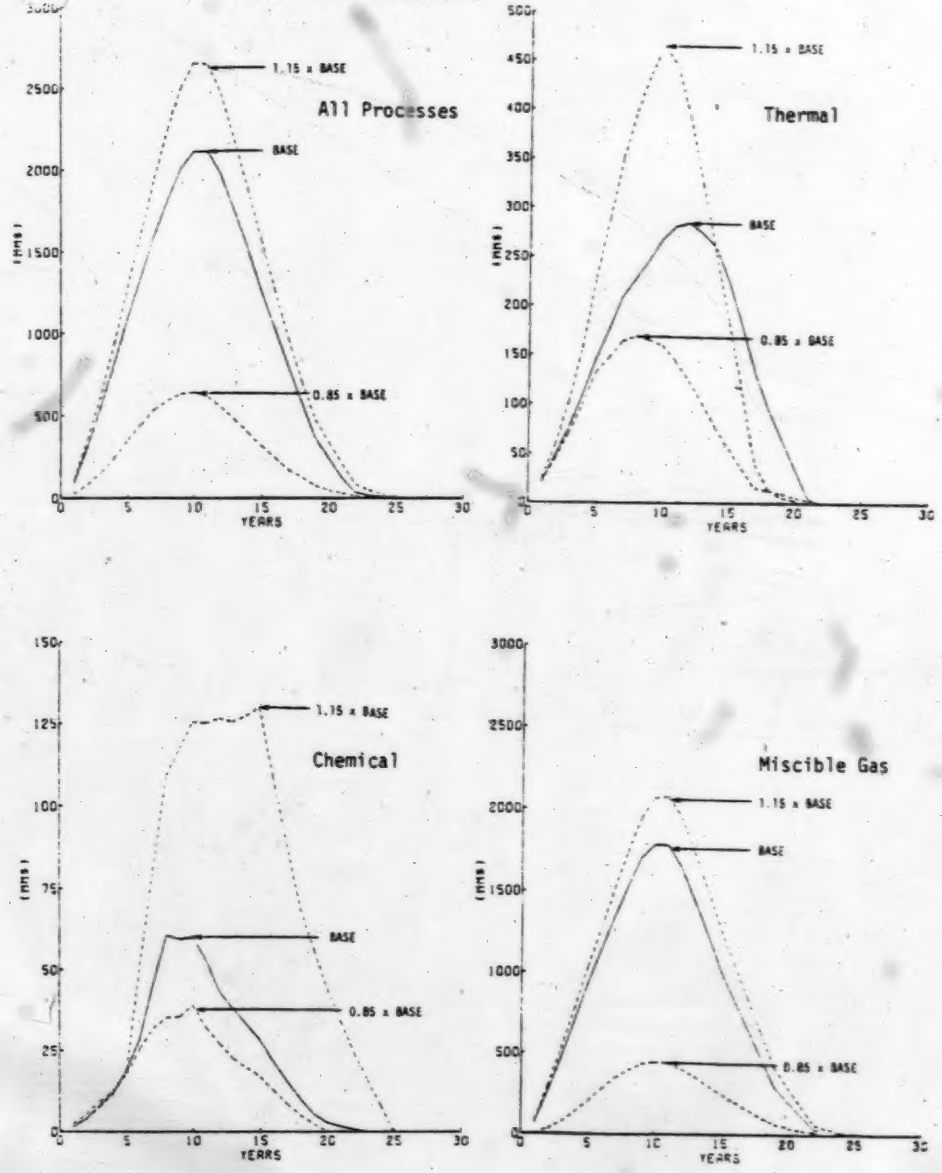


FIGURE E.24: Sensitivity of Aggregate Capital (Fixed) Costs to Changes in Recovery Factors Calculated for Individual Reservoirs

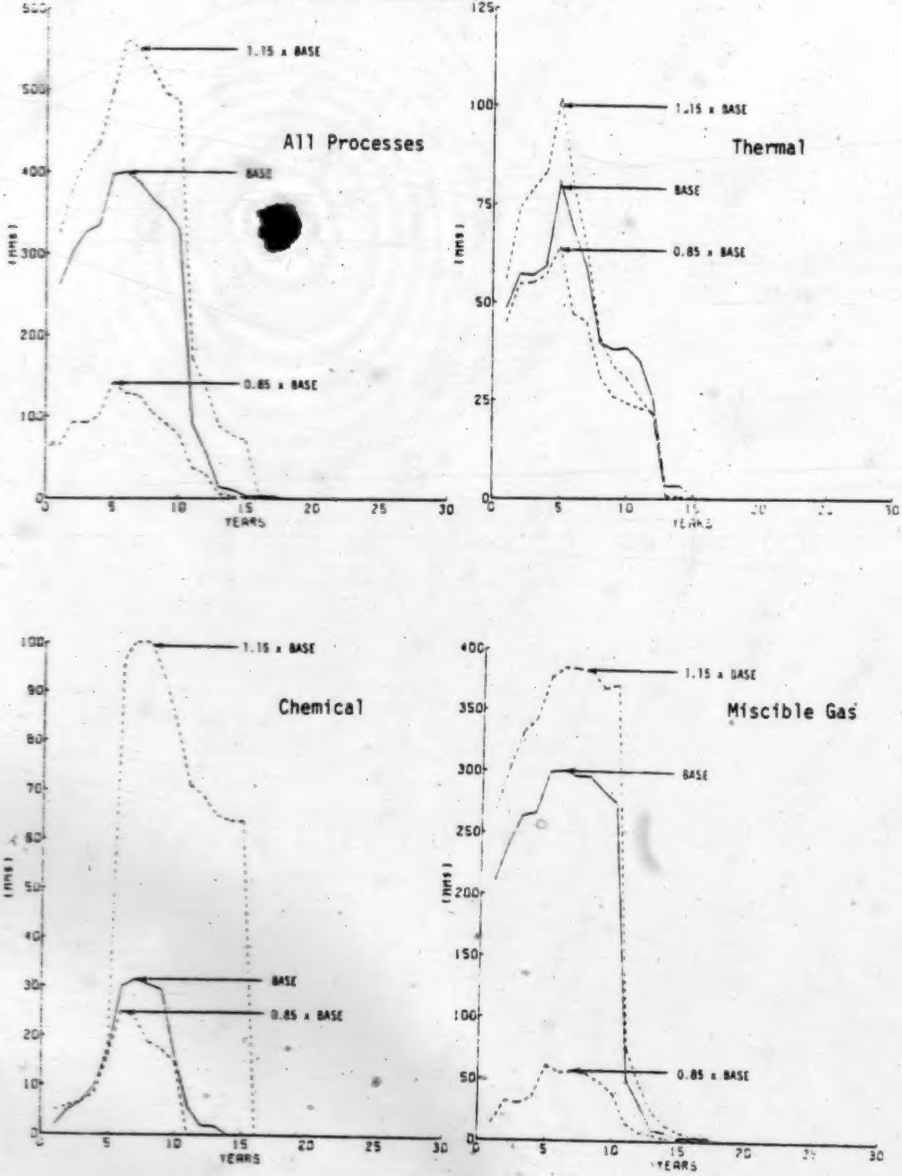


TABLE E.15

IMPACT OF TAX SYSTEM ON RECOVERY UNDER ALTERNATE RECOVERY ASSUMPTIONS

Recovery Factor	Recovery (Optimal Tax & Royalty Regulations) (MMbbl)	Recovery (Current Tax & Royalty Regulations) (MMbbl)	Recovery Tax Impact (MMbbl)
1.15 x base	3,360	3,321	39
Base	2,706	2,407	299
0.85 x base	1,821	796	1,025

TABLE E.16

POTENTIAL AND REALIZED SOCIAL VALUE UNDER ALTERNATE RECOVERY ASSUMPTIONS

	Potential Net Social Value ($billion)	Realized Net Social Value ($billion)	Change in Net Social Value Attributable to the Impact of the Tax System ($billion)
1.15 x base	11.5	11.4	0.1
Base	7.4	7.0	0.4
0.85 x base	3.6	3.3	0.3

E.3.5 Revenue Shares and Recovery Factors

Revenue shares are divided similarly in all three cases with the industry share lying between 30 and 40 percent. Since industry is already earning a real return of 8 percent (15 percent nominal) their share of net revenue shown in Table E.17 is excess to the minimum requirement to keep them in the activity of enhanced oil recovery.

TABLE E.17

DIVISION OF REALIZED NET SOCIAL VALUE BETWEEN INDUSTRY AND GOVERNMENT

Recovery Factor	Total Net Revenue	After Tax Net Revenue	% of Total	Tax Take	% of Total
1.15 x base	11,435	4,037	35	7,398	65
Base	7,005	2,450	35	4,555	65
0.85 x base	3,308	1,336	40	1,972	60

E.3.6 General Impact of Recovery Factor Variations on Economic Results

Table E.18 shows the realized after tax results of the variation in recovery factor. Ultimate production, net revenue, and taxes vary directly with the assumed recovery factor as would be expected. It is interesting to note that moving from 0.85 to base increases recovery by 67 percent but total revenue by only 52 percent, whereas the increase from base to 1.15 base increases recovery by only 38 percent but total revenue by 63 percent. The high costs of reservoirs marginally profitable under base case conditions is evident. The flow of total revenues, taxes and net revenues is depicted in Figures E.25, E.26 and E.27, respectively.

Social value and net industry return also vary with the discount rate chosen as shown in Figures E.28 and E.29. Although not readily apparent from these figures, the social rate of return for the realized low base and high recovery cases is 58, 29 and 36 percent, respectively, and the corresponding private rates of return are 31, 17 and 21 percent.

Supply prices show considerable variation among the different cases as shown in Figure E.30. An interesting feature is that the 'all process' supply price is higher for all discount rates in the base case than in the high recovery case. This means the increase in barrels produced is sufficient to offset the increased costs required to produce them, thus reducing overall supply price. This is not surprising since the increased recovery affects all reservoirs whereas the increased costs are due primarily to a few incremental reservoirs being brought on stream.

E.4 Comparative Analysis of Sensitivity Results

Section 5.1 and the preceding sections of Appendix E provide a detailed analysis of the impact of altering each of our crucial parameters on output. This section will utilize the same data to compare the impact of variations in each of the parameters on selected items of

TABLE E.18

ECONOMIC RESULTS OF RECOVERY SENSITIVITY ANALYSIS

	Present Value				
	Net Revenue ($MM)	Taxes & Royalties ($MM)	Supply Price ($)	Internal Rate of Return (%)	Forecast Incremental Recovery (MMbbl)
All Processes					
RF = 0.85 x base	1,336	1,972	11.70	31	796
RF = 0.90 x base	1,557	2,817	14.80	15	1,725
RF = base	2,450	4,555	13.90	17	2,407
RF = 1.15 x base	4,037	7,398	12.80	21	3,321
Thermal					
RF = 0.85 x base	551	806	10.50	85	237
RF = 0.90 x base	617	933	10.10	98	260
RF = base	756	1,435	10.50	131	407
RF = 1.15 x base	1,064	2,217	10.00	231	545
Chemical					
RF = 0.85 x base	198	317	7.70	36	83
RF = 0.90 x base	215	353	8.30	37	101
RF = base	255	422	7.90	37	115
RF = 1.15 x base	314	590	11.70	22	257
Miscible					
RF = 0.85 x base	587	849	13.30	19	476
RF = 0.90 x base	725	1,532	16.40	12	1,364
RF = base	1,439	2,698	15.20	13	1,885
RF = 1.15 x base	2,659	4,591	13.70	16	2,518

FIGURE E.25

SENSITIVITY OF AGGREGATE TOTAL REVENUE TO CHANGES IN RECOVERY FACTORS CALCULATED FOR INDIVIDUAL RESERVOIRS

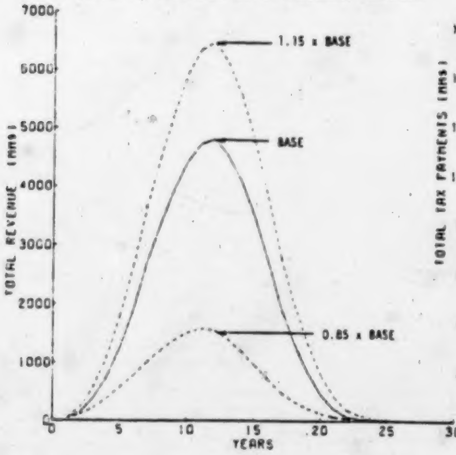


FIGURE E.26

SENSITIVITY OF TOTAL TAX PAYMENTS TO CHANGES IN RECOVERY FACTORS CALCULATED FOR INDIVIDUAL RESERVOIRS

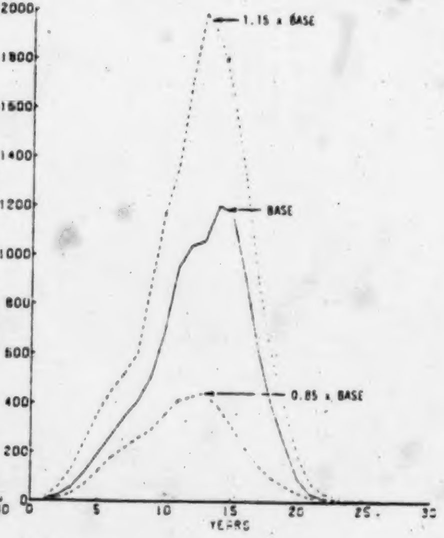


FIGURE E.27

SENSITIVITY OF INDUSTRY AGGREGATE AFTER TAX NET REVENUE TO CHANGES IN RECOVERY FACTORS CALCULATED FOR INDIVIDUAL RESERVOIRS

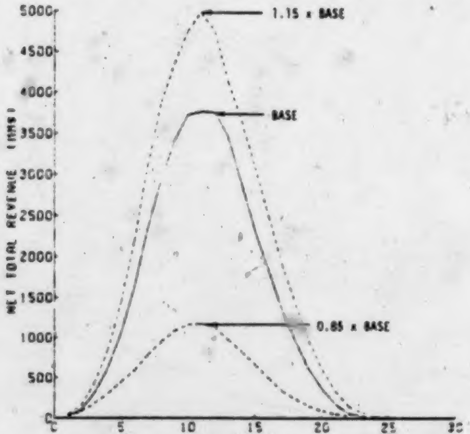


FIGURE E.28

VARIATION OF REALIZED SOCIAL VALUE FROM ENHANCED RECOVERY WITH DISCOUNT RATES UNDER ALTERNATE ASSUMPTIONS ON INDIVIDUAL RESERVOIR RECOVERY FACTORS ALL PROCESSES

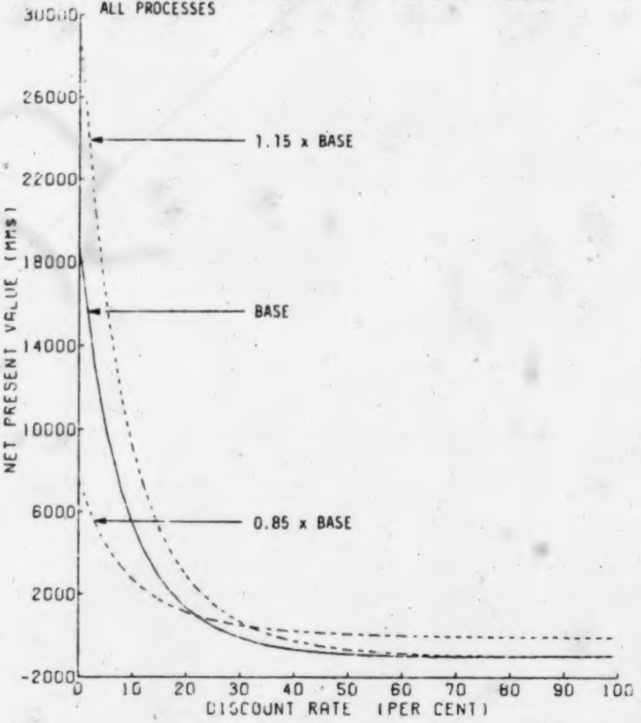


FIGURE E.29

VARIATION OF INDUSTRY AFTER TAX NET REVENUE WITH DISCOUNT RATES UNDER ALTERNATE ASSUMPTIONS ON INDIVIDUAL RESERVOIR RECOVERY FACTORS, ALL PROCESSES

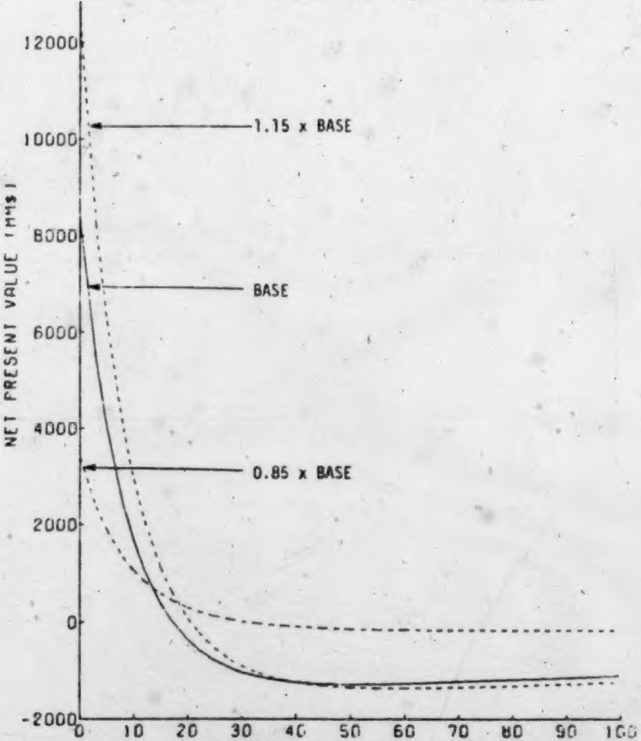
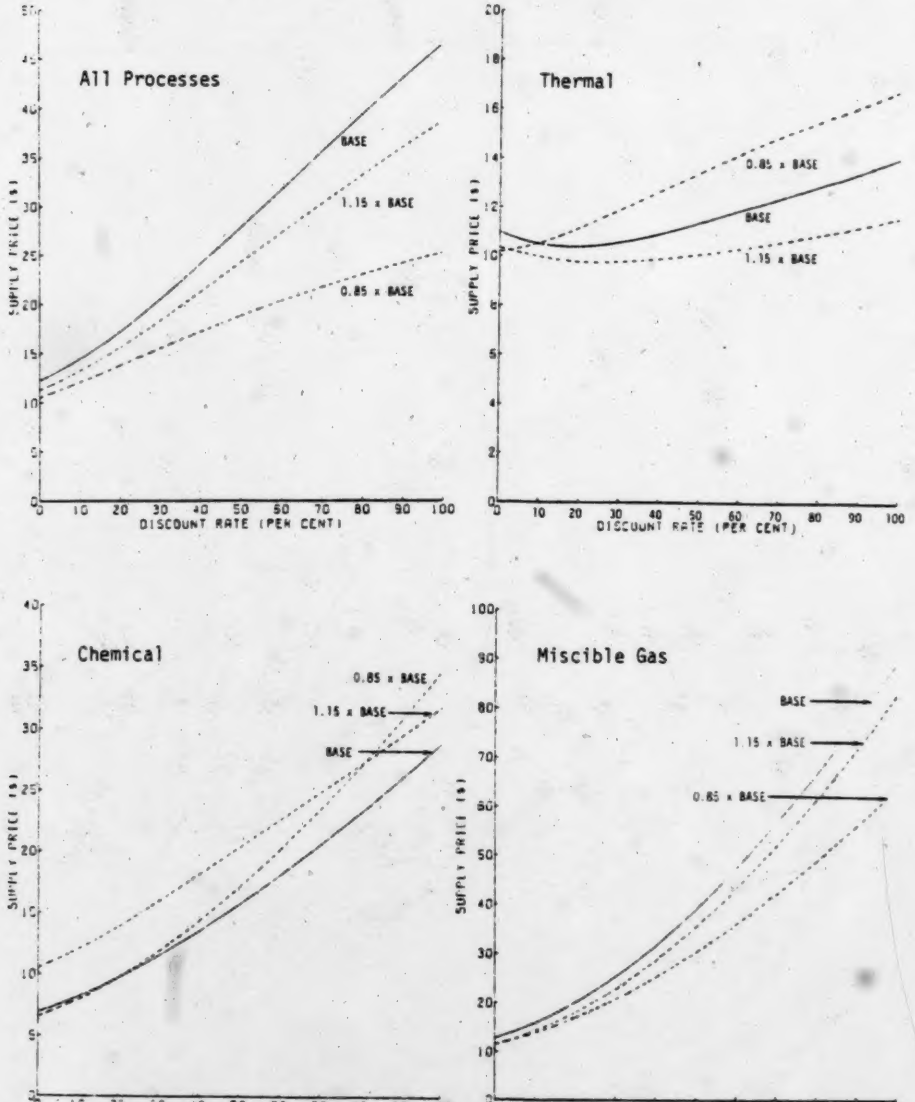


FIGURE E.30: Variation of Supply Price with Discount Rates for Assumptions on Individual Reservoir Recovery Factors



output, namely incremental recovery, supply price, internal rate of return, and net revenues.

E.4.1 The Response of Incremental Recovery, Supply Price, Internal Rate of Return, and Net Revenue to Parameter Variations

Tables E.19a and E.19b present the impact of parameter variations on incremental recovery. Direct variation in the recovery factor itself, not surprisingly, leads to the most pronounced variation in aggregate incremental recovery. Alteration of the recovery factor by ±15 percent leads to a 99 percent variation in incremental recovery, whereas comparable impacts from changes in other factors require a change of ±25 percent or more. This general tendency holds for both chemical and miscible processes. Thermal processes are distinguished by a noticeable insensitivity to pattern size variations.

Looking at individual processes, Table E.19a shows that the miscible group responds most strongly to unfavourable changes in all parameters, including the presence of a significant amount of marginally profitable oil in this group. The chemical group shows an opposite trend, that is, it responds much more strongly to favourable changes in the parameters. This seems to indicate that the marginal oil in this group is not quite viable at base case conditions but rather modest changes would bring that oil on stream. The overall results are influenced by the miscible group such that the potential for significant shortfall from our base case forecast is greater than the potential for significant overshooting of that forecast.

The cost senstivity results on incremental recovery (Tables E.20a and E.20b) looked only at the impact of a 25 percent increase in individual cost categories. The chemical processes were negligibly affected by such changes, thermal processes showed slightly less response to capital cost increases than to operating or materials costs increases but again the miscible processes showed the most notable results, extreme sensitivity to materials costs with only moderate response to increases in either capital or operating costs.

The variation in revenue (Tables E.21a and E.21b) with parameter changes was generally more pronounced than the variation in incremental recovery. In all but the chemical case, for example, the percentage increase in incremental recovery due to a favourable change in any of the four parameters is substantially less than the percentage gain in net social revenue. The direct impact of favourable changes on revenue is much more substantial than the indirect effect of such changes on costs. In the chemical case, however, favourable changes are invariably ameliorated by the opposing unfavourable changes on costs. For example, a 96 percent increase in recovery at the $25 price translates into a 66 percent increase in net social revenue. This indicates the high cost nature of the reservoirs in the chemical group that are marginal under base case conditions.

The impact on supply prices of variations in the various parameters seems to be unambiguous only for changes in the price of oil. We would expect reductions in the price of oil to eliminate high cost reservoirs and thus reduce supply price. Increases in oil price would be expected to bring on high cost reservoirs and thus increase the supply price. These expectations are borne out by the results in Tables E.22a and E.22b.

Variations in other parameters involve opposing effects that preclude a prior expectation of their impact on supply price. Increasing cost, for example, would eliminate some already marginal (high cost) reservoirs and thus could be expected to lower calculated supply prices. However, it would also increase costs for all remaining reservoirs and these costs would be allocated over a smaller number of barrels which would tend to increase supply prices. As shown in Table E.23a and E.23b, the latter effect seems to dominate in the thermal and chemical groups being considered here and the former effect wins out in the miscible group. Perhaps the most important aspect of this analysis is to point out the rather limited usefulness of the concept of the supply price in aggregate analysis.

That conclusion is equally applicable to the notion of the internal rate of return. There appear to be no grounds for expecting the overall rate of return for various process groups to change in any predictable manner in response to a change in any of our critical parameters. For completeness, we report the variations in Table E.24a and E.24b.

TABLE E.19a

SENSITIVITY RESULTS ON INCREMENTAL RECOVERY
(MMbbl)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	921	280	95	547
20 base	2,407	407	115	1,885
25	2,860	473	226	2,161
100	3,101	480	236	2,385
Recovery				
0.85 x base	796	237	83	476
0.90 x base	1,725	260	101	1,364
base	2,407	407	115	1,885
1.15 x base	3,321	545	257	2,518
Pattern Size				
0.5 x base	821	410	62	349
base	2,407	407	115	1,885
2 x base	2,944	456	231	2,257
Total Cost				
0.75 x base	2,976	491	228	2,256
base	2,407	407	115	1,885
1.25 x base	862	236	96	530

TABLE E.19b

PERCENTAGE VARIATION FROM BASE CASE INCREMENTAL RECOVERY

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	-62	-31	-31	-31
20 base	--	--	--	--
25	+19	+16	+96	+15
100	+29	+18	+105	+27
Recovery				
0.85 x base	-67	-42	-28	-75
0.90 x base	-28	-36	-12	-28
base	--	--	--	--
1.15 x base	+38	+34	+123	+34
Pattern Size				
0.5 x base	-66	+1	-46	-81
base	--	--	--	--
2 x base	+22	+12	+101	+20
Total Cost				
0.75 x base	-64	-42	-17	-72
base	--	--	--	--
1.25 x base	+24	+24	+50	+20

TABLE E.20a

COST SENSITIVITY RESULTS ON INCREMENTAL RECOVERY
(MMbbl)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Total Cost				
0.75 x base	2,976	491	228	2,256
base	2,407	407	115	1,885
1.25 x base	862	236	96	530
Capital Cost				
base	2,407	407	115	1,885
1.25 x base	1,962	310	114	1,538
Operating Cost				
base	2,407	407	115	1,885
1.25 x base	1,878	264	106	1,508
Materials Cost				
base	2,407	407	115	1,885
1.25 x base	1,047	264	110	673

TABLE E.20b

PERCENTAGE VARIATION FROM BASE CASE RECOVERY

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Total Cost				
0.75 x base	+24	+21	+98	+20
base	--	--	--	--
1.25 x base	-64	-42	-17	-72
Capital Cost				
base	--	--	--	--
1.25 x base	-18	-23	-1	-18
Operating Cost				
base	--	--	--	--
1.25 x base	-22	-35	-8	-20
Materials Cost				
base	--	--	--	--
1.25 x base	-57	-35	-4	-64

TABLE E.21a

SENSITIVITY RESULTS ON DISCOUNTED NET SOCIAL REVENUE
($MM)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	2,989	1,227	417	1,345
20 base	7,005	2,191	677	4,137
25	12,327	3,303	1,126	7,897
100				
Recovery				
0.85 x base	3,308	1,351	515	1,436
0.90 x base	4,374	1,000	568	2,257
base	7,005	2,191	677	4,137
1.15 x base	11,435	3,281	904	7,242
Pattern Size				
0.5 x base	2,856	1,648	363	845
base	7,005	2,191	677	4,137
2 x base	12,098	2,780	1,527	7,785
Total Cost				
0.75 x base	13,027	3,739	1,016	8,272
base	7,005	2,191	677	4,137
1.25 x base	3,335	1,284	584	1,467

TABLE E.21b

PERCENTAGE VARIATION FROM BASE CASE NET SOCIAL REVENUE

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	-57	-44	-38	-67
20 base	—	—	—	—
25	+76	+51	+66	+91
100				
Recovery				
0.85 x base	-52	-38	-24	-65
0.90 x base	-38	-29	-16	-45
base	—	—	—	—
1.15 x base	+63	+50	+34	+45
Pattern Size				
0.5 x base	-59	-25	-46	-79
base	—	—	—	—
2 x base	+73	+27	+126	+88
Total Cost				
0.75 x base	+86	+71	+50	100
base	—	—	—	—
1.25 x base	-52	-41	-14	-65

TABLE E.22a

SENSITIVITY RESULTS ON SUPPLY PRICE
($)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	8.60	7.80	6.10	9.60
20 base	13.90	10.50	7.90	15.20
25	16.10	13.00	15.10	17.10
100	38.10	38.40	27.60	39.10
Recovery				
0.85 x base	11.70	10.50	7.70	13.30
0.90 x base	14.80	10.10	8.30	16.40
base	13.90	10.50	7.90	15.20
1.15 x base	12.80	10.00	11.70	13.70
Pattern Size				
0.5 x base	13.00	12.60	8.20	14.40
base	13.90	10.50	7.90	15.20
2 x base	11.50	9.30	7.30	12.50
Total Cost				
0.75 x base	11.00	7.58	11.10	12.00
base	13.90	10.50	7.90	15.20
1.25 x base	12.30	10.90	8.00	13.90

TABLE E.22b

PERCENTAGE VARIATION FROM BASE CASE SUPPLY PRICE

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	-38	-26	-22	-37
20 base	—	—	—	—
25	+16	+24	+91	+13
100	+174	+266	+249	+157
Recovery				
0.85 x base	-16	0	-3	-13
0.90 x base	+6	-4	+5	+8
base	—	—	—	—
1.15 x base	-8	0	+48	-10
Pattern Size				
0.5 x base	-6	+20	+4	-5
base	—	—	—	—
2 x base	-17	-11	-8	-18
Total Cost				
0.75 x base	-21	-26	+41	-21
base	—	—	—	—
1.25 x base	-12	+4	+1	-9

TABLE E.23a

COST SENSITIVITY RESULTS ON SUPPLY PRICE

($)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Total Cost				
0.25 x base	11.00	7.58	11.10	12.00
base	13.90	10.50	7.90	15.20
1.25 x base	12.30	10.90	8.00	13.90
Capital Cost				
base	13.90	10.50	7.90	15.20
1.25 x base	13.80	10.00	8.30	15.30
Operating Cost				
base	13.90	10.50	7.90	15.20
1.25 x base	14.40	9.40	7.80	16.00
Materials Cost				
base	13.90	10.50	7.90	15.20
1.25 x base	12.10	10.20	7.90	13.90

TABLE E.23b

PERCENTAGE VARIATION FROM BASE CASE SUPPLY PRICE

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Total Cost				
0.25 x base	-21	-28	+41	-21
base	—	—	—	—
1.25 x base	-12	+4	+1	-9
Capital Cost				
base	—	—	—	—
1.25 x base	-1	-5	+5	+1
Operating Cost				
base	—	—	—	—
1.25 x base	+4	-10	-1	+5
Materials Cost				
base	—	—	—	—
1.25 x base	-13	-3	0	-9

TABLE E.24a

SENSITIVITY RESULTS ON INTERNAL RATE OF RETURN (%)

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	31	76	34	20
20 base	17	131	37	13
25	20	232	18	17
100	56	-	53	42
Recovery				
0.85 x base	31	85	36	19
0.90 x base	15	98	37	12
base	17	131	37	13
1.15 x base	21	231	22	16
Pattern Size				
0.5 x base	27	88	34	14
base	17	131	37	13
2 x base	25	225	44	20
Total Cost				
0.75 x base	27	664	21	21
base	17	131	37	13
1.25 x base	27	69	34	17

TABLE E.24b

PERCENTAGE VARIATION FROM BASE CASE RATE OF RETURN

Sensitivity Case	All Processes	Thermal	Chemical	Miscible
Price				
15	+82	−42	−8	+54
20 base	—	—	—	—
25	+18	+77	−51	+31
100	+229		+43	+223
Recovery				
0.85 x base	+82	−35	−3	+46
0.90 x base	−12	−25	0	−8
base	—	—	—	—
1.15 x base	+24	+76	−41	+23
Pattern Size				
0.5 x base	+59	−33	−8	+8
base	—	—	—	—
2 x base	+47	+72	+19	+54
Total Cost				
0.75 x base	+59	+407	−43	+62
base	—	—	—	—
1.25 x base	+59	−47	−8	+31

Footnotes

[1] The recovery case differs from the others in that it is not physically possible for other cases to exceed the technical limit on production established at the screening stage. Nonetheless, the point being made here is valid since this limit was never reached in any of the 'optimistic' cases; it was essentially a non-binding constraint.

APPENDIX F

APPENDIX F

LIST OF RESERVOIRS THAT MAY BE TECHNICALLY AND ECONOMICALLY AMENABLE TO ENHANCED OIL RECOVERY

F.1 Technical Candidates

This section lists reservoirs that qualify as technical possibilities for enhanced recovery operations in that they successfully completed the PRI screening procedure. They are listed by process and, since some reservoirs qualify for more than one process (i.e., steam drive and in situ combustion), there is considerable duplication of reservoirs listed. Section F.2 eliminates this duplication by applying economic criteria to the list of technical possibilities.

Reservoirs Successfully Completing the PRI Screening Procedures for Steam Cycle

```
0100   bodo              upper mannville b
0440   hayter            dina b
0602   lloydminster      sparky r
0606   lloydminster      sparky v
0610   lloydminster      sparky   general     petroleum/c d total
```

Reservoirs Successfully Completing the PRI Screening Procedures for Steam Drive

```
0100   bodo              upper mannville b
0440   hayter            dina b
```

Reservoirs Successfully Completing the PRI Screening Procedures for In Situ Combustion

```
0031    alderson              lower mannville f
0032    alderson              lower mannville g
0035    alderson              lower mannville j
0071    bantry                mannville j
0072    bantry                mannville m
0073    bantry                mannville o
0097    black butte           mannville b
0102    bodo                  upper mannville d
0107    bonnyville            colony b
0149    cessford              mannville x
0156    chauvin               mannville a total
0166    chauvin south         sparky h
0168    chauvin south         sparky m
0170    chauvin south         sparky a b total
0173    chauvin south         lloydminster a
0176    chauvin south         lloydminster e
0209    countess              upper mannville d      total
0220    countess              upper mannville p
0253    david                 lloydminster b
0397    grand forks           upper mannville b
0398    grand forks           lower mannville a
0399    grand forks           lower mannville b
0400    grand forks           lower mannville c
0401    grand forks           lower mannville d
0404    grand forks           lower mannville h
0406    grand forks           lower mannville j
0407    grand forks           lower mannville k
0410    grand forks           lower mannville n
0430    hays                  lower mannville a     water flood
0432    hays                  lower mannville c
0433    hays                  lower mannville d
0439    hayter                dina a
0481    jenner                upper mannville h
0482    jenner                upper mannville m
0483    jenner                upper mannville o
0484    jenner                lower mannville a
0590    lloydminster          sparky f
0591    lloydminster          sparky g
0593    lloydminster          sparky i
0595    lloydminster          sparky k
0599    lloydminster          sparky o
0600    lloydminster          sparky p
0601    lloydminster          sparky q
0602    lloydminster          sparky r
0603    lloydminster          sparky s
0605    lloydminster          sparky u
0606    lloydminster          sparky v
0607    lloydminster          sparky w
0609    lloydminster          sparky c   general    petroleum a
0610    lloydminster          sparky   general      petroleum c n total
0614    lloydminster          sparky d   general    petroleum b
0616    lloydminster          lloydminster a
0815    provost               mannville h
0816    provost               mannville i
0966    ronalane              lower mannville a
0967    ronalane              lower mannville b
1076    taber south           mannville b total
1079    taber south           mannville c
1114    viking kinsella       wainwright b
1247    wainwright            lloydminster a

1248    warwick               upper mannville j
1274    wildmere              lloydminster a
1275    wildmere              lloydminster b
1309    wrentham              lower mannville b     water flood
1310    wrentham              lower mannville c
```

Reservoirs Successfully Completing the PRI Screening Procedures for Polymer

0005	acheson	blairmore g		
0007	acheson	blairmore j		
0016	aden	bow island b		
0017	aerial	mannville gas flood		
0018	alderson	upper mannville a		
0019	alderson	upper mannville b		
0020	alderson	upper mannville c		
0021	alderson	upper mannville d		
0027	alderson	lower mannville b		
0032	alderson	lower mannville g		
0068	bantry	mannville g		
0069	bantry	mannville h		
0072	bantry	mannville m		
0073	bantry	mannville o		
0088	berry	lower mannville a		
0092	bigoray	ostracod b		
0097	black butte	mannville b		
0103	bonnie glen	cardium a		
0107	bonnyville	colony b		
0109	boundary lake south	triassic c	water flood	
0113	boundary lake south	triassic f		
0115	brazeau river	viking a		
0116	brazeau river	viking b		
0122	campbell-namao	namao blairmore c		
0125	campbell-namao	namao blairmore f		
0126	caroline	cardium a		
0128	caroline	cardium c		
0146	cessford	mannville d		
0149	cessford	mannville x		
0150	cessford	mannville y		
0151	cessford	mannville z		
0159	chauvin	mannville p		
0168	chauvin south	sparky m		
0169	chauvin south	sparky n		
0173	chauvin south	lloydminster a		
0209	countess	upper mannville d	total	
0216	countess	upper mannville j		
0217	countess	upper mannville l		
0218	countess	upper mannville m		
0220	countess	upper mannville p		
0221	countess	lower mannville a		
0222	countess	lower mannville b		
0224	countess	basal quartz b		
0225	coutts	moulton a	water flood	
0227	coutts	moulton c		
0239	crossfield east	cardium c		
0240	crossfield east	cardium d		
0245	cyn-pem	primary area		
0247	cyn-pem	cardium b		
0252	david	lloydminster a		
0256	drumheller	mannville a		
0257	drumheller	mannville f		
0258	drumheller	mannville i		
0259	drumheller	mannville k		
0269	edson	cardium a		
0278	enchant	upper mannville b		
0280	enchant	lower mannville b		
0336	ghost pine	upper mannville v		
0343	ghost pine	lower mannville b		
0344	ghost pine	lower mannville e		
0353	gilby	viking c		
0360	gilby	basal mannville f		
0363	gilby	basal mannville h l	jurassic e	glauc
0366	gilby	jurassic i		
0380	glen park	glauconitic b		
0397	grand forks	upper mannville b		
0401	grand forks	lower mannville d		
0403	grand forks	lower mannville g		
0407	grand forks	lower mannville k		
0410	grand forks	lower mannville n		
0418	harmattan east	blairmore		
0427	harold lake	colony		
0431	hays	lower mannville b		
0432	hays	lower mannville c		
0433	hays	lower mannville d		
0434	hays	lower mannville f		

Polymer (Continued)

0435	hayter	sparky a	water flood
0436	hayter	sparky b	
0437	hayter	sparky c	
0438	hayter	sparky d	
0448	hussar	glauconitic a	
0449	hussar	glauconitic b	
0450	hussar	glauconitic c	
0451	hussar	glauconitic e	
0452	hussar	glauconitic f	
0454	hussar	glauconitic h	
0455	hussar	glauconitic k	
0456	hussar	glauconitic u	
0457	hussar	glauconitic bb	
0458	hussar	glauconitic dd	
0459	hussar	ostracod c	
0461	hussar	ostracod p	
0463	hussar	basal mannville c	
0464	hussar	basal mannville e	
0465	hussar	basal mannville g	
0466	hussar	basal mannville h	
0467	hussar	basal mannville l	
0472	hussar	basal mannville o	
0473	hussar	basal mannville y	
0475	hussar	basal mannville i z	
0476	innisfail	blairmore	
0502	judy creek	viking a	
0515	keho	colorado a	
0517	killam	viking e	
0518	kirkpatrick	viking a	
0519	knappen	lower mannville a	
0520	knappen	lower mannville b	
0521	knappen	lower mannville c	
0546	lathom	upper mannville a	water flood
0547	lathom	upper mannville c	
0549	lathom	upper mannville e	
0550	lathom	lower mannville a	
0555	leckie	lower mannville a	
0557	leduc-woodbend	blairmore b	
0558	leduc-woodbend	blairmore c	
0559	leduc-woodbend	blairmore d	
0560	leduc-woodbend	blairmore e	
0561	leduc-woodbend	blairmore g	
0580	leedale	cardium a	
0583	little bow	upper mannville d	
0585	little bow	upper mannville g	
0607	lloydminster	sparky w	
0632	manyberries	sunburst a	
0633	manyberries	sunburst b	
0634	manyberries	sunburst c	
0636	manyberries	sunburst l	
0642	medicine river	cardium a	
0643	medicine river	cardium b	
0649	medicine river	ostracod a	water flood
0651	medicine river	ostracod c	
0660	medicine river	basal quartz c	
0661	medicine river	basal quartz d	
0662	medicine river	basal quartz f	
0664	medicine river	basal quartz h	
0665	medicine river	basal quartz i	
0666	medicine river	basal quartz j	
0667	medicine river	basal quartz k	
0697	minnehik-buck lake	cardium a	
0700	mitsue	primary area	
0704	morinville	lower mannville f	
0710	nevis	blairmore b	
0711	nevis	blairmore c	
0727	nipisi	keg river	sandstone a
0745	parflesh	lower mannville b	
0753	pembina	keystone belly	river b total
0762	pembina	belly river j	
0764	pembina	keystone belly	river l total
0767	pembina	keystone belly	river m water flood
0772	pembina	belly river bb	
0773	pembina	keystone belly	river cc
0774	pembina	belly river dd	
0775	pembina	belly river ee	
0776	pembina	belly river ii	
0777	pembina	belly river jj	
0778	pembina	belly river kk	
0797	pendant d oreille	mannville d	
0798	pendant d oreille	mannville f	

Polymer (Continued)

0799	penhold	lower mannville a	
0803	plain	colony e	
0806	princess	basal mannville o	
0812	provost	viking cak total	
0815	provost	mannville h	
0816	provost	mannville i	
0909	red coulee	moulton a	water flood
0935	red earth	granite wash j	
0936	red earth	granite wash k	
0938	red earth	granite wash m	
0940	red earth	granite wash o	
0942	retlaw	mannville a	
0944	retlaw	mannville i	
0946	retlaw	mannville p	
0948	retlaw	mannville r	
0949	richdale	lower mannville c	
0952	ricinus	cardium c	
0958	ricinus	cardium k	
0961	ricinus	cardium o	
0968	rosebud	blairmore	
0976	samson	blairmore a	
0986	seiu lake	lower mannville c	
1003	stanmore	upper mannville b	
1005	stanmore	lower mannville a b	
1043	sylvan lake	basal quartz a	
1082	taber south-east	mannville d	
1095	turin	upper mannville b	
1109	utikuma lake	keg river	sandstone a
1110	utikuma lake	keg river	sandstone b
1247	wainwright	lloydminster a	
1250	wayne-rosedale	glauconitic c	
1251	wayne-rosedale	glauconitic e	
1256	wayne-rosedale	basal quartz e	
1257	wayne-rosedale	basal quartz f	
1259	wayne-rosedale	basal quartz h	
1260	wayne-rosedale	basal quartz o	
1261	wayne-rosedale	basal quartz u	
1272	whitemud	blairmore	
1275	wildmere	lloydminster b	
1294	wintering hills	viking a	

Reservoirs Successfully Completing the PRI Screening Procedures for Microemulsion

0016	aden	bow island b		
0017	aerial	mannville gas flood		
0018	alderson	upper mannville a		
0020	alderson	upper mannville c		
0021	alderson	upper mannville d		
0027	alderson	lower mannville b		
0028	alderson	lower mannville c		
0029	alderson	lower mannville d		
0031	alderson	lower mannville f		
0032	alderson	lower mannville g		
0035	alderson	lower mannville j		
0086	bellshill lake	viking a		
0088	berry	lower mannville a		
0092	bigoray	ostracod b		
0097	black butte	mannville b		
0102	bodo	upper mannville d		
0115	brazeau river	viking a		
0116	brazeau river	viking b		
0126	caroline	cardium a		
0128	caroline	cardium c		
0143	cessford	basal colorado a		
0146	cessford	mannville d		
0148	cessford	mannville i		
0149	cessford	mannville x		
0150	cessford	mannville y		
0151	cessford	mannville z		
0205	conrad	ellis		
0209	countess	upper mannville d	total	
0212	countess	upper mannville f	total	
0216	countess	upper mannville j		
0217	countess	upper mannville l		
0218	countess	upper mannville m		
0220	countess	upper mannville p		
0221	countess	lower mannville a		
0222	countess	lower mannville b		
0224	countess	basal quartz b		
0225	coutts	moulton a	water flood	
0227	coutts	moulton c		
0239	crossfield east	cardium c		
0240	crossfield east	cardium d		
0247	cyn-pem	cardium b		
0256	drumheller	mannville a		
0257	drumheller	mannville f		
0258	drumheller	mannville i		
0259	drumheller	mannville k		
0278	enchant	upper mannville b		
0280	enchant	lower mannville b		
0336	ghost pine	upper mannville v		
0341	ghost pine	upper mannville	cghp u	
0343	ghost pine	lower mannville b		
0344	ghost pine	lower mannville e		
0353	gilby	viking c		
0360	gilby	basal mannville f		
0363	gilby	basal mannville h l	jurassic e	glauc
0366	gilby	jurassic i		
0397	grand forks	upper mannville b		
0400	grand forks	lower mannville c		
0401	grand forks	lower mannville d		
0402	grand forks	lower mannville e		
0403	grand forks	lower mannville g		
0407	grand forks	lower mannville k		
0410	grand forks	lower mannville n		
0412	grand forks	sawtooth a		
0417	hanna	lower mannville a		
0418	harmattan east	blairmore		
0430	hays	lower mannville a	water flood	
0431	hays	lower mannville b		
0432	hays	lower mannville c		
0433	hays	lower mannville d		
0434	hays	lower mannville f		
0448	hussar	glauconitic a		
0449	hussar	glauconitic b		
0450	hussar	glauconitic c		
0451	hussar	glauconitic e		
0457	hussar	glauconitic bb		
0458	hussar	glauconitic dd		

Microemulsion (Continued)

0459	hussar	ostracod c	
0460	hussar	ostracod h	
0461	hussar	ostracod p	
0462	hussar	basal mannville a	
0463	hussar	basal mannville c	
0464	hussar	basal mannville e	
0465	hussar	basal mannville g	
0466	hussar	basal mannville h	
0469	hussar	basal mannville n	
0471	hussar	basal mannville p	
0472	hussar	basal mannville q	
0473	hussar	basal mannville y	
0475	hussar	basal mannville i z	
0502	judy creek	viking a	
0515	keho	colorado a	
0518	kirkpatrick	viking a	
0519	knappen	lower mannville a	
0520	knappen	lower mannville b	
0521	knappen	lower mannville c	
0546	lathom	upper mannville a	water flood
0547	lathom	upper mannville c	
0549	lathom	upper mannville e	
0550	lathom	lower mannville a	
0555	leckie	lower mannville a	
0580	leedale	cardium a	
0583	little bow	upper mannville d	
0607	lloydminster	sparky w	
0632	manyberries	sunburst a	
0633	manyberries	sunburst b	
0634	manyberries	sunburst c	
0636	manyberries	sunburst l	
0642	medicine river	cardium a	
0643	medicine river	cardium b	
0649	medicine river	ostracod a	water flood
0651	medicine river	ostracod c	
0660	medicine river	basal quartz c	
0661	medicine river	basal quartz d	
0662	medicine river	basal quartz f	
0664	medicine river	basal quartz h	
0665	medicine river	basal quartz i	
0666	medicine river	basal quartz j	
0667	medicine river	basal quartz k	
0697	minnehik-buck lake	cardium a	
0727	nipisi	keg river	sandstone a
0745	parflesh	lower mannville b	
0797	pendant d oreille	mannville d	
0798	pendant d oreille	mannville f	
0799	penhold	lower mannville a	
0805	princess	basal mannville e	
0807	princess	basal mannville p	
0812	provost	viking cak total	
0909	red coulee	moulton a	water flood
0910	red coulee	moulton b total	
0913	red coulee	moulton c	water flood
0942	retlaw	mannville a	
0943	retlaw	mannville f	
0944	retlaw	mannville i	
0946	retlaw	mannville p	
0949	richdale	lower mannville c	
0966	ronalane	lower mannville a	
0967	ronalane	lower mannville b	
0968	rosebud	blairmore	
0986	seiu lake	lower mannville c	
1005	stanmore	lower mannville a b	
1073	taber north	taber a	
1092	taber south-east	mannville d	
1095	turin	upper mannville b	
1096	turin	lower mannville b	
1097	turin	lower mannville c	
1250	wayne-rosedale	glauconitic c	
1251	wayne-rosedale	glauconitic e	
1294	wintering hills	viking a	

Reservoirs Successfully Completing the PRI Screening Procedures for Alkaline

0019	alderson	upper mannville b	
0023	alderson	upper mannville f	
0053	ante creek	dunvegan a	
0061	auburndale	wainwright b	
0115	brazeau river	viking a	
0407	grand forks	lower mannville k	
0410	grand forks	lower mannville n	
0441	hazeldine	mannville a	
0607	lloydminster	sparky w	
0648	medicine river	glauconitic f	
0698	minnehik-buck lake	viking a	
0750	peco	cadomin a	
0806	princess	basal mannville o	
0964	rivercourse	colony a	
0965	rivercourse	sparky a	
1004	stanmore	lower mannville e	
1072	taber	mannville g	
1079	taber south	mannville c	
1095	turin	upper mannville b	
1098	turin	lower mannville e	
1104	turin	lower mannville m	
1251	wayne-rosedale	glauconitic e	
1280	willesden green	belly river l	
0016	aden	bow island b	
0017	aerial	mannville gas flood	
0018	alderson	upper mannville a	
0020	alderson	upper mannville c	
0021	alderson	upper mannville d	
0022	alderson	upper mannville e	
0027	alderson	lower mannville b	
0030	alderson	lower mannville e	
0032	alderson	lower mannville g	
0103	bonnie glen	cardium a	
0116	brazeau river	viking b	
0146	cessford	mannville d	
0149	cessford	mannville x	
0150	cessford	mannville y	
0151	cessford	mannville z	
0153	cessford	mannville ff	
0179	cherhill	banff b	
0180	chigwell	viking a	
0224	countess	basal quartz b	
0225	coutts	moulton a	water flood
0227	coutts	moulton c	
0232	crossfield	jumping pound a	
0239	crossfield east	cardium c	
0240	crossfield east	cardium d	
0247	cyn-pem	cardium b	
0256	drumheller	mannville a	
0257	drumheller	mannville f	
0258	drumheller	mannville i	
0259	drumheller	mannville k	
0260	drumheller	mannville l	
0278	enchant	upper mannville b	
0279	enchant	upper mannville d	
0280	enchant	lower mannville b	
0303	ferrier	belly river a	
0304	ferrier	belly river b	
0340	ghost pine	upper mannville nn	
0353	gilby	viking c	

Alkaline (Continued)

0362	gilby	basal mannville q		
0363	gilby	basal mannville h l	jurassic e	glauc
0397	grand forks	upper mannville b		
0401	grand forks	lower mannville d		
0403	grand forks	lower mannville g		
0418	harmattan east	blairmore		
0431	hays	lower mannville b		
0432	hays	lower mannville c		
0433	hays	lower mannville d		
0434	hays	lower mannville f		
0465	hussar	basal mannville g		
0475	hussar	basal mannville i z		
0513	kaybob south	primary area		
0515	keho	colorado a		
0516	killam	viking a		
0517	killam	viking e		
0518	kirkpatrick	viking a		
0552	lator	dunvegan a		
0632	manyberries	sunburst a		
0633	manyberries	sunburst b		
0634	manyberries	sunburst c		
0636	manyberries	sunburst l		
0664	medicine river	basal quartz h		
0665	medicine river	basal quartz i		
0666	medicine river	basal quartz j		
0667	medicine river	basal quartz k		
0676	medicine river	jurassic k		
0697	minnehik-buck lake	cardium a		
0727	nipisi	keg river	sandstone a	
0731	normandville	jurassic a		
0740	olds	viking a		
0748	peco	cardium a		
0749	peco	cardium b		
0793	pembina	cardium b		
0794	pembina	cardium c		
0795	pembina	keystone ellerslie a		
0797	pendant d oreille	mannville d		
0798	pendant d oreille	mannville f		
0803	plain	colony e		
0809	princess	basal mannville r		
0812	provost	viking cak total		
0909	red coulee	moulton a	water flood	
0916	red coulee	cut bank b and	rundle b	
0942	retlaw	mannville a		
0946	retlaw	mannville p		
0947	retlaw	mannville q		
0948	retlaw	mannville r		
0949	richdale	lower mannville c		
0968	rosebud	blairmore		
1002	stanmore	upper mannville a		
1003	stanmore	upper mannville b		
1005	stanmore	lower mannville a b		
1006	stettler	lower mannville a		
1044	sylvan lake	detrital b		
1082	taber south-east	mannville d		
1101	turin	lower mannville i		
1114	viking kinsella	wainwright b		
1262	wayne-rosedale	banff a		
1295	wintering hills	lower mannville a		

Reservoirs Successfully Completing the PRI Screening Procedures for Carbon Dioxide Miscible, Sandstone Reservoirs

0018	alderson	upper mannville a	
0020	alderson	upper mannville c	
0021	alderson	upper mannville d	
0022	alderson	upper mannville e	
0026	alderson	lower mannville a	
0027	alderson	lower mannville b	
0028	alderson	lower mannville c	
0029	alderson	lower mannville d	
0030	alderson	lower mannville e	
0031	alderson	lower mannville f	
0032	alderson	lower mannville g	
0035	alderson	lower mannville j	
0038	alexis	ostracod a	
0068	bantry	mannville g	
0069	bantry	mannville h	
0071	bantry	mannville j	
0072	bantry	mannville m	
0073	bantry	mannville o	
0086	bellshill lake	viking a	
0088	berry	lower mannville a	
0092	bigoray	ostracod b	
0097	black butte	mannville b	
0101	bodo	upper mannville c	
0103	bonnie glen	cardium a	
0108	boundary lake south	triassic b	
0109	boundary lake south	triassic c	water flood
0113	boundary lake south	triassic f	
0116	brazeau river	viking b	
0126	caroline	cardium a	
0128	caroline	cardium c	
0143	cessford	basal colorado a	
0146	cessford	mannville d	
0148	cessford	mannville i	
0149	cessford	mannville x	
0150	cessford	mannville y	
0151	cessford	mannville z	
0153	cessford	mannville ff	
0156	chauvin	mannville a total	
0159	chauvin	mannville b	
0162	chauvin south	sparky e total	
0165	chauvin south	sparky f	
0166	chauvin south	sparky h	
0167	chauvin south	sparky i	
0169	chauvin south	sparky n	
0170	chauvin south	sparky a b total	
0179	cherhill	banff b	
0182	chigwell	mannville c	
0188	chin coulee	basal mannville a	total
0205	conrad	ellis	
0209	countess	upper mannville d	total
0212	countess	upper mannville f	total
0216	countess	upper mannville j	
0217	countess	upper mannville l	
0218	countess	upper mannville m	
0221	countess	lower mannville a	
0222	countess	lower mannville b	
0224	countess	basal quartz b	
0225	coutts	moulton a	water flood
0227	coutts	moulton c	
0228	crossfield	cardium a total	
0232	crossfield	jumping pound a	
0239	crossfield east	cardium c	
0240	crossfield east	cardium d	
0247	cyn-pem	cardium b	
0252	david	lloydminster a	
0253	david	lloydminster b	
0269	edson	cardium a	
0276	ellerslie	blairmore a	
0278	enchant	upper mannville b	
0279	enchant	upper mannville d	
0280	enchant	lower mannville b	
0305	ferrier	cardium a	
0307	ferrier	cardium c	
0308	ferrier	cardium d total	
0311	ferrier	cardium e total	

Carbon Dioxide Miscible, Sandstone Reservoirs (Continued)

0314	ferrier	cardium f		
0315	ferrier	cardium g		
0318	ferrier	cardium j		
0335	ghost pine	upper mannville q		
0338	ghost pine	upper mannville hh		
0343	ghost pine	lower mannville b		
0344	ghost pine	lower mannville e		
0353	gilby	viking c		
0360	gilby	basal mannville f		
0362	gilby	basal mannville q		
0363	gilby	basal mannville h l	jurassic e	glauc
0380	glen park	glauconitic b		
0396	grand forks	upper mannville a		
0397	grand forks	upper mannville b		
0398	grand forks	lower mannville a		
0399	grand forks	lower mannville b		
0400	grand forks	lower mannville c		
0401	grand forks	lower mannville d		
0402	grand forks	lower mannville e		
0403	grand forks	lower mannville g		
0412	grand forks	sawtooth a		
0417	hanna	lower mannville a		
0418	harmattan east	blairmore		
0430	hays	lower mannville a	water flood	
0431	hays	lower mannville b		
0432	hays	lower mannville c		
0433	hays	lower mannville d		
0434	hays	lower mannville f		
0435	hayter	sparky a	water flood	
0436	hayter	sparky b		
0437	hayter	sparky c		
0438	hayter	sparky d		
0439	hayter	dina a		
0476	innisfail	blairmore		
0508	kaybob	cadomin b		
0509	kaybob	cadomin c		
0516	killam	viking a		
0517	killam	viking e		
0518	kirkpatrick	viking a		
0519	knappen	lower mannville a		
0520	knappen	lower mannville b		
0546	lathom	upper mannville a	water flood	
0547	lathom	upper mannville c		
0552	lator	dunvegan a		
0555	leckie	lower mannville a		
0559	leduc-woodbend	blairmore d		
0580	leedale	cardium a		
0582	legal	mannville b		
0583	little bow	upper mannville d		
0586	little bow	upper mannville h		
0623	lubicon	granite wash a		
0642	medicine river	cardium a		
0643	medicine river	cardium b		
0649	medicine river	ostracod a	water flood	
0651	medicine river	ostracod c		
0654	medicine river	ostracod p		
0660	medicine river	basal quartz c		
0661	medicine river	basal quartz d		
0662	medicine river	basal quartz f		
0664	medicine river	basal quartz h		
0665	medicine river	basal quartz i		
0666	medicine river	basal quartz j		
0667	medicine river	basal quartz k		
0674	medicine river	jurassic d	water flood	
0676	medicine river	jurassic k		
0697	minnehik-buck lake	cardium a		
0702	mitsue	gilwood c		
0703	morinville	lower mannville a		
0704	morinville	lower mannville f		
0705	morinville	lower mannville l		
0710	nevis	blairmore b		
0711	nevis	blairmore c		
0727	nipisi	keg river	sandstone a	
0728	niton	cardium a		
0729	niton	basal quartz a		
0731	normandville	jurassic a		
0748	peco	cardium a		
0749	peco	cardium b		
0780	pembina	belly river mm		
0785	pembina	cardium total		
0797	pendant d oreille	mannville d		

Carbon Dioxide Miscible, Sandstone Reservoirs (Continued)

0805	princess	basal mannville e	
0807	princess	basal mannville p	
0808	princess	basal mannville q	
0815	provost	mannville h	
0909	red coulee	moulton a	water flood
0910	red coulee	moulton b total	
0913	red coulee	moulton c	water flood
0915	red coulee	cut bank c	
0916	red coulee	cut bank b and	rundle b
0933	red earth	granite wash f	
0934	red earth	granite wash i	
0935	red earth	granite wash j	
0936	red earth	granite wash k	
0937	red earth	granite wash l	
0938	red earth	granite wash m	
0939	red earth	granite wash n	
0942	retlaw	mannville a	
0943	retlaw	mannville f	
0944	retlaw	mannville i	
0946	retlaw	mannville p	
0947	retlaw	mannville q	
0948	retlaw	mannville r	
0950	ricinus	cardium a	
0951	ricinus	cardium b	
0952	ricinus	cardium c	
0958	ricinus	cardium k	
0959	ricinus	cardium l	
0961	ricinus	cardium o	
0966	ronalane	lower mannville a	
0967	ronalane	lower mannville b	
0968	rosebud	blairmore	
0976	samson	blairmore a	
1002	stanmore	upper mannville a	
1003	stanmore	upper mannville b	
1013	sturgeon lake south	triassic a	
1038	sylvan lake	cardium a	
1042	sylvan lake	ostracod a	
1043	sylvan lake	basal quartz a	
1044	sylvan lake	detrital b	
1045	sylvan lake	jurassic a	
1047	sylvan lake	jurassic c	
1049	sylvan lake	jurassic e	
1051	sylvan lake	jurassic j	
1065	taber	mannville a	
1071	taber	mannville f	
1073	taber north	taber a	
1074	taber north	taber b	
1082	taber south-east	mannville d	
1099	turin	lower mannville g	
1100	turin	lower mannville h	
1101	turin	lower mannville i	
1109	utikuma lake	keg river	sandstone a
1110	utikuma lake	keg river	sandstone b
1112	verger	upper mannville c	
1247	wainwright	lloydminster a	
1248	warwick	upper mannville j	
1262	wayne-rosedale	banff a	
1281	willesden green	cardium a total	
1294	wintering hills	viking a	
1295	wintering hills	lower mannville a	
1296	wintering hills	lower mannville e	
0223	countess	lower mannville c	
0404	grand forks	lower mannville h	
0411	grand forks	lower mannville o	
0585	little bow	upper mannville g	
0784	pembina	keystone belly	river qq
0903	plain	colony e	
0809	princess	basal mannville r	
1005	stanmore	lower mannville a b	
1066	taber	mannville c	
1067	taber	mannville d total	
1072	taber	mannville g	
1075	taber south	mannville a	water flood
1076	taber south	mannville b total	
1079	taber south	mannville c	
1080	taber south-east	mannville a	
1103	turin	lower mannville l	
1104	turin	lower mannville m	
1308	wrentham	lower mannville a	
1309	wrentham	lower mannville b	water flood
1310	wrentham	lower mannville c	

Reservoirs Successfully Completing the PRI Screening Procedures for Carbon Dioxide Miscible, Carbonate Reservoirs

0041	alix	d-2	
0049	amber	keg river f	
0079	bashaw	d-3 a	
0080	bashaw	d-3 b	
0090	bigoray	primary area	
0091	bigoray	water flood area	
0095	black	keg river a	water flood
0096	black	keg river b	
0118	buffalo lake	d-3	
0119	buffalo lake	d-3 b	
0131	caroline	elkton b	
0132	caroline	elkton c	
0137	carson creek north	primary area	
0138	carson creek north	water flood area	
0140	carson creek north	primary area	
0141	carson creek north	water flood area	
0142	carstairs	elkton b	
0184	chigwell	d-2 b	
0185	chigwell	d-2 c	
0186	chigwell	d-2 d	
0192	claresholm	rundle a	
0193	claresholm	rundle b	
0194	claresholm	rundle c	
0201	clive	d-2 c	
0203	clive	primary area	
0235	crossfield	rundle c	
0236	crossfield	rundle e	
0237	crossfield	rundle g	
0241	crossfield east	elkton a	
0243	crossfield east	elkton d	
0251	davey	d-2 b	
0281	erskine	d-2	
0283	ethel	beaverhill lake a	
0295	fairydell-bon accord	d-3 a	
0298	fenn-big valley	big valley d-3 b	
0299	fenn-big valley	fenn d-3 c	
0301	fenn-big valley	fenn d-3 f	
0322	ferrier	shunda a	
0327	freeman	primary area	
0328	freeman	water flood area	
0370	gilby	rundle e	
0372	gilby	rundle k	
0373	gilby	rundle l	
0390	golden	slave point a	
0391	goose river	d-2 a	
0393	goose river	primary area	
0394	goose river	water flood area	
0395	goose river	beaverhill lake b	
0413	greencourt	pekisko a	
0414	greencourt	pekisko c	
0421	harmattan east	water flood area	
0423	harmattan-elkton	rundle b	
0425	harmattan-elkton	primary area	
0426	harmattan-elkton	water flood area	
0429	haynes	d-3 a	
0442	homeglen-rimbey	d-3	
0503	judy creek	beaverhill lake a	water flood
0504	judy creek	beaverhill lake b	water flood
0505	judy creek south	beaverhill lake	water flood
0507	judy creek south	beaverhill lake c	
0510	kaybob	beaverhill lake a	water flood
0511	kaybob	beaverhill lake b	
0526	lanaway	d-3 a	
0528	larne	keg river a	
0529	larne	keg river b	
0530	larne	keg river c	
0531	larne	keg river d	
0532	larne	keg river e	
0534	larne	keg river g	
0536	larne	keg river i	
0537	larne	keg river j	
0538	larne	keg river k	
0539	larne	keg river l	
0540	larne	keg river m	
0542	larne	keg river D	
0543	larne	keg river p	

Carbon Dioxide Miscible, Carbonate Reservoirs (Continued)

0544	larne	keg river q	
0619	lone pine creek	d-3 a	
0620	loon	slave point a	water flood
0624	majeau lake	banff b	
0627	malmo	d-3 a	
0628	malmo	d-3 c	
0640	matziwin	pekisko a	
0641	matziwin	pekisko b	
0677	medicine river	elkton - shunda a	
0679	medicine river	elkton-shunda c	
0680	medicine river	shunda a	
0681	medicine river	pekisko b	water flood
0682	medicine river	pekisko c	
0683	medicine river	pekisko d	
0685	medicine river	primary area	
0686	medicine river	water flood area	
0687	medicine river	pekisko f	
0690	medicine river	pekisko i	
0692	medicine river	pekisko r	
0693	medicine river	pekisko s	
0694	meekwap	d-2 a water flood	
0695	mikwan	d-2 a	
0696	mikwan	d-3 a	
0713	nevis	d-3 b	
0714	nevis	d-3 c	
0715	nevis	d-3 d	
0716	nevis	d-3 e	
0717	nevis	d-3 f	
0732	normandville	mississippian b	
0739	open creek	banff a	
0743	paddle river	d-2 a	
0796	pembina	pekisko a	
0801	penhold	d-3 a	
0804	pouce coupe south	boundary a	
0810	princess	pekisko a	
0846	rainbow	keg river w	
0855	rainbow	keg river hh	
0861	rainbow	keg river nn	
0887	rainbow	keg river qqq	
0892	rainbow south	sulphur point b	
0893	rainbow south	muskeg a	
0895	rainbow south	muskeg d	
0896	rainbow south	keg river a	water flood
0900	rainbow south	keg river e	water flood
0901	rainbow south	keg river f	
0902	rainbow south	keg river g	water flood
0904	rainbow south	keg river i	
0905	rainbow south	keg river j	
0907	rainbow south	keg river l	
0908	rainbow south	keg river m	
0917	red coulee	rundle a	
0918	reagan	rundle a	
0920	red earth	primary area	
0921	red earth	water flood area	
0922	red earth	slave point b	
0923	red earth	slave point c	
0924	red earth	slave point d	
0925	red earth	slave point e	
0977	senex	keg river a	
0978	shekilie	muskeg a	
0980	shekilie	keg river b	
0982	shekilie	keg river d	
0983	shekilie	keg river e	
0984	shekilie	keg river f	
0985	shekilie	keg river g	
0989	snipe lake	beaverhill lake	water flood
0990	sousa	sulphur point a	
1008	stettler	d-3 a	
1009	stettler	d-3 b	
1010	stettler south	d-2	
1011	stettler south	d-3	
1015	sturgeon lake south	d-2 a	
1017	sturgeon lake south	d-3 b	
1019	sundre	primary area	
1020	sundre	water flood area	
1022	sundre	primary area	
1023	sundre	water flood area	
1026	swalwell	d-2 a	
1027	swalwell	d-2 b	

Carbon Dioxide Miscible, Carbonate Reservoirs (Continued)

1029	swan hills	primary area	
1030	swan hills	water flood area	
1032	swan hills	primary area	
1033	swan hills	water flood area	
1035	swan hills south	primary area	
1036	swan hills south	solvent flood	
1037	swan hills south	water flood area	
1053	sylvan lake	elkton b	
1054	sylvan lake	elkton c	
1055	sylvan lake	elkton e	
1056	sylvan lake	elkton f	
1058	sylvan lake	pekisko b	
1059	sylvan lake	pekisko c	
1061	sylvan lake	pekisko e	
1063	sylvan lake	pekisko m	
1064	sylvan lake	d-3 a	
1085	tehze	muskeg b	
1086	tehze	muskeg c	
1087	tehze	keg river a	
1093	turner valley	rundle water flood	
1102	turin	lower mannville k	
1106	twining north	rundle	
1117	virginia hills	primary area	
1118	virginia hills	water flood area	
1124	virgo	muskeg g	water flood
1125	virgo	muskeg h	
1131	virgo	keg river a	
1133	virgo	keg river c	
1136	virgo	keg river f	
1138	virgo	keg river h	
1142	virgo	keg river l	
1148	virgo	keg river r	water flood
1165	virgo	keg river ii	
1167	virgo	keg river kk	
1203	virgo	keg river uuu	
1211	virgo	keg river c2c	
1237	virgo	keg river c3c	
1238	virgo	keg river d3c	
1240	virgo	keg river f3f	
1241	virgo	keg river g3g	
1242	virgo	keg river h3h	
1245	wainwright	primary area	
1246	wainwright	water flood area	
1265	west drumheller	d-3 a	
1266	westerose	d-3	
1269	westward ho	primary area	
1270	westward ho	water flood area	
1290	wimborne	d-3 a	
1302	wood river	d-2 a	
1304	wood river	d-2 c	
1305	wood river	d-3 a	
1321	zama	muskeg b	
1334	zama	muskeg t	
1335	zama	muskeg u	
1336	zama	muskeg v	
1340	zama	muskeg aa	
1342	zama	muskeg dd	
1344	zama	muskeg gg	
1347	zama	muskeg kk	
1352	zama	keg river a	
1367	zama	keg river r	
1373	zama	keg river s	
1379	zama	keg river dd	
1387	zama	keg river ll	
1401	zama	keg river zz	
1405	zama	keg river ddd	
1410	zama	keg river iii	
1416	zama	keg river ooo	
1423	zama	keg river www	
1425	zama	keg river yyy	
1426	zama	keg river zzz	
1430	zama	keg river e2e	
1438	zama	keg river m2m	
1443	zama	keg river r2r	
1445	zama	keg river t2t	
1446	zama	keg river u2u	
1451	zama	keg river z2z	
1454	zama	keg river c3c	
1456	zama	keg river f3f	

Carbon Dioxide Miscible, Carbonate Reservoirs (Continued)

1457	zama	keg river g3g
1469	zama	keg river s3s
1484	zama	keg river h4h
1485	zama	keg river i4i
1486	zama	keg river j4j
1487	zama	keg river k4k
1490	zama	keg river n4n
1491	zama	keg river o4o
1492	zama	keg river p4p
1493	zama	keg river q4q
1494	zama	keg river r4r
1495	zama	keg river s4s
1499	zama	keg river w4w
1503	zama	keg river a5a
1505	zama	keg river c5c
0037	alexander	wabamun b
0293	fairydell-bon accord	d-2 a
0294	fairydell-bon accord	d-2 b
0415	greencourt	pekisko d
1206	virgo	keg river xxx
1210	virgo	keg river b2b
1315	youngstown	arcs
1322	zama	muskeg c
1348	zama	muskeg ll
1357	zama	keg river g
1369	zama	keg river t
1380	zama	keg river ee
1411	zama	keg river jjj
1481	zama	keg river e4e

Reservoirs Successfully Completing the PRI Screening Procedures for Hydrocarbon Miscible, Sandstone Reservoirs

0018	alderson	upper mannville a	
0020	alderson	upper mannville c	
0021	alderson	upper mannville d	
0022	alderson	upper mannville e	
0026	alderson	lower mannville a	
0027	alderson	lower mannville b	
0028	alderson	lower mannville c	
0029	alderson	lower mannville d	
0030	alderson	lower mannville e	
0031	alderson	lower mannville f	
0032	alderson	lower mannville g	
0035	alderson	lower mannville j	
0038	alexis	ostracod a	
0068	bantry	mannville g	
0069	bantry	mannville h	
0071	bantry	mannville j	
0072	bantry	mannville m	
0073	bantry	mannville o	
0086	bellshill lake	viking a	
0088	berry	lower mannville a	
0092	bigoray	ostracod b	
0097	black butte	mannville b	
0101	bodo	upper mannville c	
0103	bonnie glen	cardium a	
0108	boundary lake south	triassic b	
0109	boundary lake south	triassic c	water flood
0113	boundary lake south	triassic f	
0116	brazeau river	viking b	
0126	caroline	cardium a	
0128	caroline	cardium c	
0143	cessford	basal colorado a	
0146	cessford	mannville d	
0148	cessford	mannville i	
0149	cessford	mannville x	
0150	cessford	mannville y	
0151	cessford	mannville z	
0153	cessford	mannville ff	
0156	chauvin	mannville a total	
0159	chauvin	mannville b	
0162	chauvin south	sparky e total	
0165	chauvin south	sparky f	
0166	chauvin south	sparky h	
0167	chauvin south	sparky i	
0169	chauvin south	sparky n	
0170	chauvin south	sparky a b total	
0179	cherhill	banff b	
0182	chigwell	mannville c	
0188	chin coulee	basal mannville a	total
0205	conrad	ellis	
0209	countess	upper mannville d	total
0212	countess	upper mannville f	total
0216	countess	upper mannville j	
0217	countess	upper mannville l	
0218	countess	upper mannville m	
0221	countess	lower mannville a	
0222	countess	lower mannville b	
0224	countess	basal quartz b	
0225	coutts	moulton a	water flood
0227	coutts	moulton c	
0228	crossfield	cardium a total	
0232	crossfield	jumping pound a	
0239	crossfield east	cardium c	
0240	crossfield east	cardium d	
0247	cyn-pem	cardium b	
0252	david	lloydminster a	
0253	david	lloydminster b	
0269	edson	cardium a	
0276	ellerslie	blairmore a	
0278	enchant	upper mannville b	
0279	enchant	upper mannville d	
0280	enchant	lower mannville b	
0305	ferrier	cardium a	
0307	ferrier	cardium c	
0308	ferrier	cardium d total	
0311	ferrier	cardium e total	
0314	ferrier	cardium f	

Hydrocarbon Miscible, Sandstone Reservoirs

0315	ferrier	cardium g		
0318	ferrier	cardium j		
0335	ghost pine	upper mannville g		
0338	ghost pine	upper mannville hh		
0343	ghost pine	lower mannville b		
0344	ghost pine	lower mannville e		
0353	gilby	viking c		
0360	gilby	basal mannville f		
0362	gilby	basal mannville g		
0363	gilby	basal mannville h i	jurassic e	glauc
0390	glen park	glauconitic b		
0396	grand forks	upper mannville a		
0397	grand forks	upper mannville b		
0398	grand forks	lower mannville a		
0399	grand forks	lower mannville b		
0400	grand forks	lower mannville c		
0401	grand forks	lower mannville d		
0402	grand forks	lower mannville e		
0403	grand forks	lower mannville g		
0412	grand forks	sawtooth a		
0417	hanna	lower mannville a		
0418	harmattan east	blairmore		
0430	hays	lower mannville a	water flood	
0431	hays	lower mannville b		
0432	hays	lower mannville c		
0433	hays	lower mannville d		
0434	hays	lower mannville f		
0435	hayter	sparky a	water flood	
0436	hayter	sparky b		
0437	hayter	sparky c		
0438	hayter	sparky d		
0439	hayter	dina a		
0476	innisfail	blairmore		
0508	kaybob	cadomin b		
0509	kaybob	cadomin c		
0516	killam	viking a		
0517	killam	viking e		
0518	kirkpatrick	viking a		
0519	knappen	lower mannville a		
0520	knappen	lower mannville b		
0546	lathom	upper mannville a	water flood	
0547	lathom	upper mannville c		
0552	lator	dunvegan a		
0555	leckie	lower mannville a		
0559	leduc-woodbend	blairmore d		
0580	leedale	cardium a		
0582	legal	mannville b		
0583	little bow	upper mannville d		
0586	little bow	upper mannville h		
0623	lubicon	granite wash a		
0642	medicine river	cardium a		
0643	medicine river	cardium b		
0649	medicine river	ostracod a	water flood	
0651	medicine river	ostracod c		
0654	medicine river	ostracod d		
0660	medicine river	basal quartz c		
0661	medicine river	basal quartz d		
0662	medicine river	basal quartz f		
0664	medicine river	basal quartz h		
0665	medicine river	basal quartz i		
0666	medicine river	basal quartz j		
0667	medicine river	basal quartz k		
0674	medicine river	jurassic d	water flood	
0676	medicine river	jurassic k		
0697	minnehik-buck lake	cardium a		
0702	mitsue	gilwood c		
0703	morinville	lower mannville a		
0704	morinville	lower mannville f		
0705	morinville	lower mannville i		
0710	nevis	blairmore b		
0711	nevis	blairmore c		
0727	nipisi	keg river	sandstone a	
0728	niton	cardium a		
0729	niton	basal quartz a		
0731	normandville	jurassic a		
0748	peco	cardium a		
0749	peco	cardium b		
0780	pembina	belly river mm		
0785	pembina	cardium total		
0797	pendant d oreille	mannville d		

Hydrocarbon Miscible, Sandstone Reservoirs

0805	princess	basal mannville e	
0807	princess	basal mannville p	
0808	princess	basal mannville q	
0815	provost	mannville h	
0909	red coulee	moulton a	water flood
0910	red coulee	moulton b total	
0913	red coulee	moulton c	water flood
0915	red coulee	cut bank c	
0916	red coulee	cut bank b and	rundle b
0933	red earth	granite wash f	
0934	red earth	granite wash i	
0935	red earth	granite wash j	
0936	red earth	granite wash k	
0937	red earth	granite wash l	
0938	red earth	granite wash m	
0939	red earth	granite wash n	
0942	retlaw	mannville a	
0943	retlaw	mannville f	
0944	retlaw	mannville i	
0946	retlaw	mannville p	
0947	retlaw	mannville q	
0948	retlaw	mannville r	
0950	ricinus	cardium a	
0951	ricinus	cardium b	
0952	ricinus	cardium c	
0958	ricinus	cardium k	
0959	ricinus	cardium l	
0961	ricinus	cardium o	
0966	ronalane	lower mannville a	
0967	ronalane	lower mannville b	
0968	rosebud	blairmore	
0976	samson	blairmore a	
1002	stanmore	upper mannville a	
1003	stanmore	upper mannville b	
1013	sturgeon lake south	triassic a	
1038	sylvan lake	cardium a	
1042	sylvan lake	ostracod a	
1043	sylvan lake	basal quartz a	
1044	sylvan lake	detrital b	
1045	sylvan lake	jurassic a	
1047	sylvan lake	jurassic c	
1049	sylvan lake	jurassic e	
1051	sylvan lake	jurassic j	
1065	taber	mannville a	
1071	taber	mannville f	
1073	tauer north	taber a	
1074	taber north	taber b	
1082	taber south-east	mannville d	
1099	turin	lower mannville g	
1100	turin	lower mannville h	
1101	turin	lower mannville i	
1109	utikuma lake	keg river	sandstone a
1110	utikuma lake	keg river	sandstone b
1112	verger	upper mannville c	
1247	wainwright	lloydminster a	
1248	warwick	upper mannville j	
1262	wayne-rosedale	banff a	
1281	willesden green	cardium a total	
1294	wintering hills	viking a	
1295	wintering hills	lower mannville a	
1296	wintering hills	lower mannville e	
0223	countess	lower mannville c	
0404	grand forks	lower mannville h	
0411	grand forks	lower mannville o	
0585	little bow	upper mannville g	
0784	pembina	keystone belly	river qq
0803	plain	colony e	
0809	princess	basal mannville r	
1005	stanmore	lower mannville a b	
1066	taber	mannville c	
1067	taber	mannville d total	
1072	taber	mannville g	
1075	taber south	mannville a	water flood
1076	taber south	mannville b total	
1079	taber south	mannville c	
1080	taber south-east	mannville a	
1103	turin	lower mannville l	
1104	turin	lower mannville m	
1308	wrentham	lower mannville a	
1309	wrentham	lower mannville b	water flood
1310	wrentham	lower mannville c	

Reservoirs Successfully Completing the PRI Screening Procedures for Hydrocarbon Miscible, Carbonate Reservoirs

0041	alix	d-2	
0049	amber	keg river f	
0079	bashaw	d-3 a	
0080	bashaw	d-3 b	
0090	bigoray	primary area	
0091	bigoray	water flood area	
0095	black	keg river a	water flood
0096	black	keg river b	
0118	buffalo lake	d-3	
0119	buffalo lake	d-3 b	
0131	caroline	elkton b	
0132	caroline	elkton c	
0137	carson creek north	primary area	
0138	carson creek north	water flood area	
0140	carson creek north	primary area	
0141	carson creek north	water flood area	
0142	carstairs	elkton b	
0184	chigwell	d-2 b	
0185	chigwell	d-2 c	
0186	chigwell	d-2 d	
0192	claresholm	rundle a	
0193	claresholm	rundle b	
0194	claresholm	rundle c	
0201	clive	d-2 c	
0203	clive	primary area	
0235	crossfield	rundle c	
0236	crossfield	rundle e	
0237	crossfield	rundle g	
0241	crossfield east	elkton a	
0243	crossfield east	elkton d	
0251	davey	d-2 b	
0281	erskine	d-2	
0283	ethel	beaverhill lake a	
0295	fairydell-bon accord	d-3 a	
0298	fenn-big valley	big valley d-3 b	
0299	fenn-big valley	fenn d-3 c	
0301	fenn-big valley	fenn d-3 f	
0322	ferrier	shunda a	
0327	freeman	primary area	
0328	freeman	water flood area	
0370	gilby	rundle e	
0372	gilby	rundle k	
0373	gilby	rundle l	
0390	golden	slave point a	
0391	goose river	d-2 a	
0393	goose river	primary area	
0394	goose river	water flood area	
0395	goose river	beaverhill lake b	
0413	greencourt	pekisko a	
0414	greencourt	pekisko c	
0421	harmattan east	water flood area	
0423	harmattan-elkton	rundle b	
0425	harmattan-elkton	primary area	
0426	harmattan-elkton	water flood area	
0429	haynes	d-3 a	
0442	homeglen-rimbey	d-3	
0503	judy creek	beaverhill lake a	water flood
0504	judy creek	beaverhill lake b	water flood
0505	judy creek south	beaverhill lake	water flood
0507	judy creek south	beaverhill lake c	
0510	kaybob	beaverhill lake a	water flood
0511	kaybob	beaverhill lake b	
0526	lanaway	d-3 a	
0528	larne	keg river a	
0529	larne	keg river b	
0530	larne	keg river c	
0531	larne	keg river d	
0532	larne	keg river e	
0534	larne	keg river g	
0536	larne	keg river i	
0537	larne	keg river j	
0538	larne	keg river k	
0539	larne	keg river l	
0540	larne	keg river m	
0542	larne	keg river 0	
0543	larne	keg river p	

Hydrocarbon Miscible, Carbonate Reservoirs (Continued)

0544	larne	keg river q	
0619	lone pine creek	d-3 a	
0620	loon	slave point a	water flood
0624	majeau lake	banff b	
0627	malmo	d-3 a	
0628	malmo	d-3 c	
0640	matziwin	pekisko a	
0641	matziwin	pekisko b	
0677	medicine river	elkton - shunda a	
0679	medicine river	elkton-shunda c	
0680	medicine river	shunda a	
0681	medicine river	pekisko b	water flood
0682	medicine river	pekisko c	
0683	medicine river	pekisko d	
0685	medicine river	primary area	
0686	medicine river	water flood area	
0687	medicine river	pekisko f	
0690	medicine river	pekisko i	
0692	medicine river	pekisko r	
0693	medicine river	pekisko s	
0694	meekwap	d-2 a water flood	
0695	mikwan	d-2 a	
0696	mikwan	d-3 a	
0713	nevis	d-3 b	
0714	nevis	d-3 c	
0715	nevis	d-3 d	
0716	nevis	d-3 e	
0717	nevis	d-3 f	
0732	normandville	mississippian b	
0739	open creek	banff a	
0743	paddle river	d-2 a	
0796	pembina	pekisko a	
0801	penhold	d-3 a	
0804	pouce coupe south	boundary a	
0810	princess	pekisko a	
0846	rainbow	keg river w	
0855	rainbow	keg river hh	
0861	rainbow	keg river nn	
0887	rainbow	keg river qqq	
0892	rainbow south	sulphur point b	
0893	rainbow south	muskeg a	
0895	rainbow south	muskeg d	
0896	rainbow south	keg river a	water flood
0900	rainbow south	keg river e	water flood
0901	rainbow south	keg river f	
0902	rainbow south	keg river g	water flood
0904	rainbow south	keg river i	
0905	rainbow south	keg river j	
0907	rainbow south	keg river l	
0908	rainbow south	keg river m	
0917	red coulee	rundle a	
0918	reagan	rundle a	
0920	red earth	primary area	
0921	red earth	water flood area	
0922	red earth	slave point b	
0923	red earth	slave point c	
0924	red earth	slave point d	
0925	red earth	slave point e	
0977	senex	keg river a	
0978	shekilie	muskeg a	
0980	shekilie	keg river b	
0982	shekilie	keg river d	
0983	shekilie	keg river e	
0984	shekilie	keg river f	
0985	shekilie	keg river g	
0989	snipe lake	beaverhill lake	water flood
0990	sousa	sulphur point a	
1008	stettler	d-3 a	
1009	stettler	d-3 b	
1010	stettler south	d-2	
1011	stettler south	d-3	
1015	sturgeon lake south	d-2 a	
1017	sturgeon lake south	d-3 b	
1019	sundre	primary area	
1020	sundre	water flood area	
1022	sundre	primary area	
1023	sundre	water flood area	
1026	swalwell	d-2 a	
1027	swalwell	d-2 b	
1029	swan hills	primary area	

Hydrocarbon Miscible, Carbonate Reservoirs (Continued)

1030	swan hills	water flood area	
1032	swan hills	primary area	
1033	swan hills	water flood area	
1035	swan hills south	primary area	
1036	swan hills south	solvent flood	
1037	swan hills south	water flood area	
1053	sylvan lake	elkton b	
1054	sylvan lake	elkton c	
1055	sylvan lake	elkton e	
1056	sylvan lake	elkton f	
1058	sylvan lake	pekisko b	
1059	sylvan lake	pekisko c	
1061	sylvan lake	pekisko e	
1063	sylvan lake	pekisko m	
1064	sylvan lake	d-3 a	
1085	tehze	muskeg b	
1086	tehze	muskeg c	
1087	tehze	keg river a	
1093	turner valley	rundle water flood	
1102	turin	lower mannville k	
1106	twining north	rundle	
1117	virginia hills	primary area	
1118	virginia hills	water flood area	
1124	virgo	muskeg g	water flood
1125	virgo	muskeg h	
1131	virgo	keg river a	
1133	virgo	keg river c	
1136	virgo	keg river f	
1138	virgo	keg river h	
1142	virgo	keg river l	
1145	virgo	keg river r	water flood
1165	virgo	keg river jj	
1167	virgo	keg river kk	
1203	virgo	keg river uuu	
1211	virgo	keg river c2c	
1237	virgo	keg river c3c	
1238	virgo	keg river d3d	
1240	virgo	keg river f3f	
1241	virgo	keg river g3g	
1242	virgo	keg river h3h	
1245	wainwright	primary area	
1246	wainwright	water flood area	
1265	west drumheller	d-3 a	
1266	westerose	d-3	
1269	westward ho	primary area	
1270	westward ho	water flood area	
1290	wimborne	d-3 a	
1302	wood river	d-2 a	
1304	wood river	d-2 c	
1305	wood river	d-3 a	
1321	zama	muskeg b	
1334	zama	muskeg t	
1335	zama	muskeg u	
1336	zama	muskeg v	
1340	zama	muskeg aa	
1342	zama	muskeg dd	
1344	zama	muskeg gg	
1347	zama	muskeg kk	
1352	zama	keg river a	
1367	zama	keg river r	
1373	zama	keg river s	
1379	zama	keg river dd	
1387	zama	keg river ll	
1401	zama	keg river ss	
1405	zama	keg river ddd	
1410	zama	keg river iii	
1416	zama	keg river ooo	
1423	zama	keg river www	
1425	zama	keg river yyy	
1426	zama	keg river zzz	
1430	zama	keg river e2e	
1438	zama	keg river m2m	
1443	zama	keg river r2r	
1445	zama	keg river t2t	
1446	zama	keg river u2u	
1451	zama	keg river z2z	
1454	zama	keg river c3c	
1456	zama	keg river f3f	
1457	zama	keg river g3g	
1469	zama	keg river s3s	

Hydrocarbon Miscible, Carbonate Reservoirs (Continued)

1484	zama	keg river h4h
1485	zama	keg river i4i
1486	zama	keg river j4j
1487	zama	keg river k4k
1490	zama	keg river n4n
1491	zama	keg river o4o
1492	zama	keg river p4p
1493	zama	keg river q4q
1494	zama	keg river r4r
1495	zama	keg river s4s
1499	zama	keg river w4w
1503	zama	keg river a5a
1505	zama	keg river c5c
0037	alexander	wabamun b
0293	fairydell-bon accord	d-2 a
0294	fairydell-bon accord	d-2 b
0415	greencourt	pekisko d
1206	virgo	keg river xxx
1210	virgo	keg river b2b
1315	youngstown	arcs
1322	zama	muskeg c
1348	zama	muskeg ll
1357	zama	keg river g
1369	zama	keg river t
1380	zama	keg river ee
1411	zama	keg river jjj
1481	zama	keg river e4e

F.2 Economically Viable Candidates

This section lists reservoirs under the processes which are economically dominant for that reservoir. That is, although a reservoir may meet the technical requirements for say, steam drive and in situ combustion, the application of one of these processes would result in a higher net present value than the other. Reservoirs listed below appear under only one process, that process which results in the highest net present value (is economically dominant). It is, however, possible that the highest net present value is negative which would mean application of even the best process would be unprofitable in that reservoir. Using our base case price of $20 per barrel and discount rate of 8 percent (real), we have identified all reservoirs that would be profitable under the assumptions of this study. It should be remembered that our models were developed with aggregate estimation in mind. They were not intended for, nor are they capable of, in-depth analysis of individual reservoirs. Therefore inclusion of a given reservoir in the list below provides only an indication of its potential viability (or lack thereof).

Reservoirs for Which the Steam Cycle Process is Dominant
(* indicates profitable pools at $20 price)

```
* 0610   lloydminster          sparky   general      petroleum c d total
```

Reservoirs for wnich the Steam Drive Process is Dominant
(* indicates profitable pools at $20 price)

```
* 0100   bodo                  upper mannville b
* 0440   hayter                dina b
```

Reservoirs for Which the In Situ Combustion Process is Dominant
(* indicates profitable pools at $20 price)

```
* 0032   alderson              lower mannville g
* 0071   bantry                mannville j
* 0072   bantry                mannville m
* 0073   bantry                mannville o
* 0397   black butte           mannville b
* 0102   bodo                  upper mannville d
* 0168   chauvin south         sparky m
* 0173   chauvin south         lloydminster a
* 0176   chauvin south         lloydminster e
* 0220   countess              upper mannville p
* 0253   david                 lloydminster b
* 0397   grand forks           upper mannville b
* 0399   grand forks           lower mannville b
* 0406   grand forks           lower mannville j
* 0407   grand forks           lower mannville k
* 0410   grand forks           lower mannville n
* 0432   hays                  lower mannville c
* 0433   hays                  lower mannville d
* 0439   hayter                dina a
  0481   jenner                upper mannville h
* 0482   jenner                upper mannville m
  0493   jenner                upper mannville o
* 0494   jenner                lower mannville a
* 0590   lloydminster          sparky f
* 0591   lloydminster          sparky g
  0593   lloydminster          sparky i
  0595   lloydminster          sparky k
* 0599   lloydminster          sparky o
* 0600   lloydminster          sparky p
* 0601   lloydminster          sparky q
* 0602   lloydminster          sparky r
* 0603   lloydminster          sparky s
* 0605   lloydminster          sparky u
* 0606   lloydminster          sparky v
* 0607   lloydminster          sparky w
  0609   lloydminster          sparky c   general     petroleum a
* 0614   lloydminster          sparky d   general     petroleum b
* 0616   lloydminster          lloydminster a
* 0815   provost               mannville h
* 0966   ronalane              lower mannville a
* 1247   wainwright            lloydminster a
* 1274   wildmere              lloydminster a
* 1275   wildmere              lloydminster b
```

Reservoirs for which the Polymer Process is Dominant
(* indicates profitable pools at $20 price)

•	0005	acheson	blairmore g	
•	0007	acheson	blairmore j	
•	0107	bonnyville	colony b	
	0115	brazeau river	viking a	
•	0122	campbell-namao	namao blairmore c	
•	0125	campbell-namao	namao blairmore f	
	0245	cyn-pem	primary area	
•	0336	ghost pine	upper mannville v	
	0427	harold lake	colony	
•	0448	hussar	glauconitic a	
•	0449	hussar	glauconitic b	
	0450	hussar	glauconitic c	
•	0452	hussar	glauconitic f	
•	0454	hussar	glauconitic h	
	0455	hussar	glauconitic k	
	0456	hussar	glauconitic u	
•	0457	hussar	glauconitic bb	
	0459	hussar	ostracod c	
	0461	hussar	ostracod p	
•	0463	hussar	basal mannville c	
	0467	hussar	basal mannville l	
•	0472	hussar	basal mannville q	
•	0473	hussar	basal mannville y	
	0502	judy creek	viking a	
	0549	lathom	upper mannville e	
	0550	lathom	lower mannville a	
	0557	leduc-woodbend	blairmore b	
	0558	leduc-woodbend	blairmore c	
•	0560	leduc-woodbend	blairmore e	
•	0561	leduc-woodbend	blairmore g	
	0700	mitsue	primary area	
•	0745	parflesh	lower mannville b	
•	0753	pembina	keystone belly	river b total
•	0762	pembina	belly river j	
	0764	pembina	keystone belly	river l total
	0767	pembina	keystone belly	river m water flood
•	0772	pembina	belly river bb	
	0773	pembina	keystone belly	river cc
	0774	pembina	belly river dd	
•	0775	pembina	belly river ee	
	0776	pembina	belly river ii	
	0777	pembina	belly river jj	
•	0778	pembina	belly river kk	
•	0816	provost	mannville i	
•	0940	red earth	granite wash o	
•	0986	seiu lake	lower mannvile c	
•	1256	wayne-rosedalr	basal quartz e	
	1257	wayne-rosedale	basal quartz f	
•	1259	wayne-rosedale	basal quartz h	
	1260	wayne-rosedale	basal quartz o	
•	1261	wayne-rosedale	basal quartz u	
•	1272	whitemud	blairmore	

Reservoirs for which the Microemulsion Process is Dominant
(* indicates profitable pools at $20 price)

•	0058	berry	lower mannville a	
	0341	ghost pine	upper mannville	cghp u
	0366	gilby	jurassic i	
•	0451	hussar	glauconitic e	
	0458	hussar	glauconitic dd	
	0460	hussar	ostracod h	
	0462	hussar	basal mannville a	
•	0464	hussar	basal mannville e	
•	0466	hussar	basal mannville h	
	0469	hussar	basal mannville n	
	0471	hussar	basal mannville p	
	0521	knappen	lower mannville c	
	0799	penhold	lower mannville a	
•	0910	red coulee	moulton b total	
	1096	turin	lower mannville b	
	1097	turin	lower mannville c	
•	1250	wayne-rosedale	glauconitic c	

Reservoirs for which the Alkaline Process is Dominant
(* indicates profitable pools at $20 price)

* 0019	alderson	upper mannville b		
* 0023	alderson	upper mannville f		
* 0053	ante creek	dunvegan a		
* 0061	auburndale	wainwright b		
* 0441	hazeldine	mannville a		
* 0648	medicine river	glauconitic f		
0698	minnehik-buck lake	viking a		
0750	peco	cadomin a		
* 0806	princess	basal mannville o		
* 0964	rivercourse	colony a		
* 0965	rivercourse	sparky a		
* 1004	stanmore	lower mannville e		
* 1072	taber	mannville g		
* 1079	taber south	mannville c		
* 1095	turin	upper mannville b		
* 1098	turin	lower mannville e		
* 1104	turin	lower mannville m		
* 1251	wayne-rosedale	glauconitic e		
* 1280	willesden green	belly river l		
* 0016	aden	bow island c		
* 0017	aerial	mannville gas flood		
* 0021	alderson	upper mannville d		
* 0030	alderson	lower mannville e		
* 0103	bonnie glen	cardium a		
* 0149	cessford	mannville x		
* 0153	cessford	mannville ff		
* 0179	cherhill	banff b		
* 0180	chigwell	viking a		
* 0224	countess	basal quartz b		
* 0225	coutts	moulton a	water flood	
* 0227	coutts	moulton c		
* 0247	cyn-pem	cardium b		
* 0256	drumheller	mannville a		
* 0257	drumheller	mannville f		
* 0258	drumheller	mannville i		
* 0259	drumheller	mannville k		
* 0260	drumheller	mannville l		
* 0278	enchant	upper mannville b		
* 0280	enchant	lower mannville b		
* 0303	ferrier	belly river a		
* 0304	ferrier	belly river b		
0340	ghost pine	upper mannville nn		
* 0363	gilby	basal mannville h l	jurassic e	glauc
* 0401	grand forks	lower mannville d		
* 0403	grand forks	lower mannville g		
* 0418	harmattan east	blairmore		
* 0431	hays	lower mannville b		
* 0434	hays	lower mannville f		
* 0465	hussar	basal mannville q		
* 0475	hussar	basal mannville i z		
* 0513	kaybob south	primary area		
0515	keho	colorado a		
* 0632	manyberries	sunburst a		
* 0633	manyberries	sunburst b		
0634	manyberries	sunburst c		
* 0636	manyberries	sunburst l		
* 0665	medicine river	basal quartz i		
* 0666	medicine river	basal quartz j		
* 0676	medicine river	jurassic k		
* 0731	normandville	jurassic a		
* 0740	olds	viking a		
* 0793	pembina	cardium b		
* 0794	pembina	cardium c		
0795	pembina	keystone ellerslie a		
* 0797	pendant d oreille	mannville d		
* 0798	pendant d oreille	mannville f		
* 0803	plain	colony e		
* 0809	princess	basal mannville r		
0812	provost	viking cak total		
* 0909	red coulee	moulton a	water flood	
* 0916	red coulee	cut bank b and	rundle b	
* 0946	retlaw	mannville p		
* 0947	retlaw	mannville q		
* 0949	richdale	lower mannville c		
* 1003	stanmore	upper mannville b		
* 1005	stanmore	lower mannville a b		
* 1006	stettler	lower mannville a		
* 1044	sylvan lake	detrital b		
* 1082	taber south-east	mannville d		
* 1116	viking kinsella	wainwright b		
* 1262	wayne-rosedale	banff a		
* 1295	wintering hills	lower mannville a		

Reservoirs for which the Carbon Dioxide Miscible, Sandstone Reservoirs Process is Dominant (* indicates profitable pools at $20 price)

*	0101	bodo	upper mannville c	
*	0126	caroline	cardium a	
*	0156	chauvin	mannville a total	
*	0159	chauvin	mannville b	
*	0162	chauvin south	sparky e total	
*	0165	chauvin south	sparky f	
*	0166	chauvin south	sparky h	
*	0167	chauvin south	sparky i	
*	0169	chauvin south	sparky n	
*	0170	chauvin south	sparky a b total	
*	0252	david	lloydminster a	
*	0380	glen park	glauconitic b	
*	0398	grand forks	lower mannville a	
*	0430	grand forks	lower mannville c	
*	0412	grand forks	sawtooth a	
*	0435	hayter	sparky a	water flood
*	0436	hayter	sparky b	
*	0438	hayter	sparky d	
*	0508	kaybob	cadomin b	
*	0519	knappen	lower mannville a	
*	0520	knappen	lower mannville b	
*	0547	lathom	upper mannville c	
*	0555	leckie	lower mannville a	
*	0559	leduc-woodbend	blairmore d	
*	0593	little bow	upper mannville d	
	0702	mitsue	gilwood c	
*	0711	nevis	blairmore c	
*	0728	niton	cardium a	
	0749	peco	cardium b	
*	0913	red coulee	moulton c	water flood
*	0976	samson	blairmore a	
*	1051	sylvan lake	jurassic j	
*	1248	warwick	upper mannville j	
	1281	willesden green	cardium a total	
*	1294	wintering hills	viking a	

Reservoirs for which the Carbon Dioxide Miscible, Carbonate Reservoirs Process is Dominant

(* indicates profitable pools at $20 price)

* 0095	black	keg river a	water flood
* 0096	black	keg river b	
* 0391	goose river	d-2 a	
* 0503	judy creek	beaverhill lake a	water flood
0504	judy creek	beaverhill lake b	water flood
0510	kaybob	beaverhill lake a	water flood
* 0528	larne	keg river a	
* 0529	larne	keg river b	
* 0530	larne	keg river c	
* 0531	larne	keg river d	
* 0532	larne	keg river e	
* 0536	larne	keg river i	
* 0537	larne	keg river j	
* 0538	larne	keg river k	
* 0540	larne	keg river m	
* 0543	larne	keg river p	
* 0544	larne	keg river q	
* 0887	rainbow	keg river qqq	
* 0900	rainbow south	keg river r	water flood
* 0908	rainbow south	keg river m	
* 0930	shekilie	keg river b	
* 0982	shekilie	keg river d	
* 0984	shekilie	keg river f	
* 0990	sousa	sulphur point a	
1030	swan hills	water flood area	
* 1033	swan hills	water flood area	
* 1036	swan hills south	solvent flood	
1037	swan hills south	water flood area	
* 1118	virginia hills	water flood area	
1124	virgo	muskeg g	water flood
* 1138	virgo	keg river h	
* 1148	virgo	keg river r	water flood
* 1165	virgo	keg river ii	
* 1167	virgo	keg river kk	
* 1211	virgo	keg river c2c	
* 1237	virgo	keg river c3c	
* 1240	virgo	keg river f3f	
* 1241	virgo	keg river g3g	
* 1245	wainwright	primary area	
* 1246	wainwright	water flood area	
* 1334	zama	muskeg t	
1336	zama	muskeg v	
* 1344	zama	muskeg gg	
* 1352	zama	keg river a	
1367	zama	keg river r	
* 1373	zama	keg river s	
* 1379	zama	keg river dd	
* 1401	zama	keg river zz	
* 1405	zama	keg river ddd	
* 1416	zama	keg river ooo	
* 1423	zama	keg river www	
* 1425	zama	keg river yyy	
* 1430	zama	keg river e2e	
* 1438	zama	keg river m2m	
* 1446	zama	keg river u2u	
* 1451	zama	keg river z2z	
* 1456	zama	keg river f3f	
* 1469	zama	keg river s3s	
* 1484	zama	keg river h4h	
* 1486	zama	keg river j4j	
* 1494	zama	keg river r4r	
* 1495	zama	keg river s4s	
* 1499	zama	keg river w4w	
* 1503	zama	keg river a5a	
* 1505	zama	keg river c5c	
* 0415	greencourt	pekisko d	
* 1206	virgo	keg river aaa	
* 1210	virgo	keg river b2b	
* 1322	zama	muskeg c	
* 1348	zama	muskeg ll	
* 1357	zama	keg river g	
* 1380	zama	keg river ee	
* 1411	zama	keg river jjj	
* 1481	zama	keg river e4e	

Reservoirs for which the Hydrocarbon Miscible, Sandstone Reservoirs Process is Dominant (* indicates profitable pools at $20 price)

*	0018	alderson	upper mannville a	
*	0020	alderson	upper mannville c	
*	0022	alderson	upper mannville e	
*	0026	alderson	lower mannville a	
*	0027	alderson	lower mannville b	
*	0028	alderson	lower mannville c	
*	0029	alderson	lower mannville d	
*	0031	alderson	lower mannville f	
*	0035	alderson	lower mannville j	
	0038	alexis	ostracod a	
*	0068	bantry	mannville g	
*	0069	bantry	mannville h	
	0086	bellshill lake	viking a	
*	0092	bigoray	ostracod b	
*	0108	boundary lake south	triassic b	
*	0109	boundary lake south	triassic c	water flood
	0113	boundary lake south	triassic f	
	0116	brazeau river	viking b	
	0128	caroline	cardium c	
*	0143	cessford	basal colorado a	
*	0146	cessford	mannville d	
*	0148	cessford	mannville i	
*	0150	cessford	mannville y	
	0151	cessford	mannville z	
*	0182	chigwell	mannville c	
	0188	chin coulee	basal mannville a	total
	0205	conrad	ellis	
*	0209	countess	upper mannville d	total
*	0212	countess	upper mannville f	total
*	0216	countess	upper mannville j	
*	0217	countess	upper mannville l	
*	0218	countess	upper mannville m	
*	0221	countess	lower mannville a	
*	0222	countess	lower mannville b	
	0228	crossfield	cardium a total	
	0232	crossfield	jumping pound a	
	0239	crossfield east	cardium c	
	0240	crossfield east	cardium d	
	0269	edson	cardium a	
*	0276	ellerslie	blairmore a	
*	0279	enchant	upper mannville d	
*	0305	ferrier	cardium a	
	0307	ferrier	cardium c	
	0308	ferrier	cardium d total	
	0311	ferrier	cardium e total	
	0314	ferrier	cardium f	
*	0315	ferrier	cardium g	
*	0318	ferrier	cardium j	
*	0335	ghost pine	upper mannville g	
*	0338	ghost pine	upper mannville hh	
*	0343	ghost pine	lower mannville b	
*	0344	ghost pine	lower mannville e	
	0353	gilby	viking c	
	0360	gilby	basal mannville f	
	0362	gilby	basal mannville g	
*	0396	grand forks	upper mannville a	
*	0402	grand forks	lower mannville e	
*	0417	hanna	lower mannville a	
*	0430	hays	lower mannville a	water flood
*	0437	hayter	sparky c	
*	0476	innisfail	blairmore	
	0509	kaybob	cadomin c	
*	0516	killam	viking a	
	0517	killam	viking e	
*	0518	kirkpatrick	viking a	
*	0546	lathom	upper mannville a	water flood
*	0552	lator	dunvegan a	
*	0580	leedale	cardium a	
*	0582	legal	mannville b	
	0586	little bow	upper mannville h	
*	0623	lubicon	granite wash a	
*	0642	medicine river	cardium a	
*	0643	medicine river	cardium b	
	0649	medicine river	ostracod a	water flood
*	0651	medicine river	ostracod c	
*	0654	medicine river	ostracod p	

Hydrocarbon Miscible, Sandstone Reservoirs (Continued)

•	0660	medicine river	basal quartz c	
•	0661	medicine river	basal quartz d	
•	0662	medicine river	basal quartz f	
•	0664	medicine river	basal quartz h	
	0667	medicine river	basal quartz k	
•	0674	medicine river	jurassic d	water flood
	0697	minnehik-buck lake	cardium a	
•	0703	morinville	lower mannville a	
•	0704	morinville	lower mannville f	
•	0705	morinville	lower mannville i	
•	0710	nevis	blairmore b	
	0727	nipisi	keg river	sandstone a
	0729	niton	basal quartz a	
	0748	peco	cardium a	
•	0780	pembina	belly river mm	
•	0785	pembina	cardium total	
•	0805	princess	basal mannville e	
•	0807	princess	basal mannville p	
•	0808	princess	basal mannville q	
•	0915	red coulee	cut bank c	
•	0933	red earth	granite wash f	
•	0934	red earth	granite wash i	
•	0935	red earth	granite wash j	
•	0936	red earth	granite wash k	
•	0937	red earth	granite wash l	
	0938	red earth	granite wash m	
•	0939	red earth	granite wash n	
•	0942	retlaw	mannville a	
•	0943	retlaw	mannville f	
•	0944	retlaw	mannville i	
•	0948	retlaw	mannville r	
•	0950	ricinus	cardium a	
•	0951	ricinus	cardium b	
•	0952	ricinus	cardium c	
•	0958	ricinus	cardium k	
•	0959	ricinus	cardium l	
•	0961	ricinus	cardium o	
•	0967	ronalane	lower mannville b	
•	0968	rosebud	blairmore	
	1002	stanmore	upper mannville a	
•	1013	sturgeon lake south	triassic a	
	1038	sylvan lake	cardium a	
•	1042	sylvan lake	ostracod a	
•	1043	sylvan lake	basal quartz a	
•	1045	sylvan lake	jurassic a	
•	1047	sylvan lake	jurassic c	
•	1049	sylvan lake	jurassic e	
•	1065	taber	mannville a	
•	1071	taber	mannville f	
•	1073	taber north	taber a	
•	1074	taber north	taber b	
	1099	turin	lower mannville g	
•	1100	turin	lower mannville h	
	1101	turin	lower mannville i	
•	1109	utikuma lake	keg river	sandstone a
	1110	utikuma lake	keg river	sandstone b
•	1112	verger	upper mannville c	
•	1296	wintering hills	lower mannville e	
•	0223	countess	lower mannville c	
•	0404	grand forks	lower mannville h	
	0411	grand forks	lower mannville o	
•	0595	little bow	upper mannville g	
•	0784	pembina	keystone belly	river eq
•	1066	taber	mannville c	
•	1067	taber	mannville d total	
•	1075	taber south	mannville a	water flood
•	1076	taber south	mannville b total	
•	1090	taber south-east	mannville a	
•	1103	turin	lower mannville l	
•	1308	wrentham	lower mannville a	
•	1309	wrentham	lower mannville b	water flood
•	1310	wrentham	lower mannville c	

Reservoirs for which the Hydrocarbon Miscible, Carbonate Reservoirs Process is Dominant
(* indicates profitable pools at $20 price)

	0041	alix	d-2	
•	0049	amber	keg river f	
	0079	bashaw	d-3 a	
•	0080	bashaw	d-3 b	
	0090	bigoray	primary area	
	0091	bigoray	water flood area	
•	0118	buffalo lake	d-3	
•	0119	buffalo lake	d-3 b	
	0131	caroline	elkton b	
	0132	caroline	elkton c	
	0137	carson creek north	primary area	
	0138	carson creek north	water flood area	
	0140	carson creek north	primary area	
	0141	carson creek north	water flood area	
	0142	carstairs	elkton b	
	0184	chigwell	d-2 b	
	0185	chigwell	d-2 c	
	0186	chigwell	d-2 d	
•	0192	claresholm	rundle a	
•	0193	claresholm	rundle b	
	0194	claresholm	rundle c	
	0201	clive	d-2 c	
•	0203	clive	primary area	
	0235	crossfield	rundle c	
•	0236	crossfield	rundle e	
•	0237	crossfield	rundle g	
•	0241	crossfield east	elkton a	
•	0243	crossfield east	elkton d	
•	0251	davey	d-2 b	
•	0281	erskine	d-2	
	0283	ethel	beaverhill lake a	
•	0295	fairydell-bon accord	d-3 a	
	0298	fenn-big valley	big valley d-3 b	
	0299	fenn-big valley	fenn d-3 c	
	0301	fenn-big valley	fenn d-3 f	
	0322	ferrier	shunda a	
	0327	freeman	primary area	
	0328	freeman	water flood area	
	0370	gilby	rundle e	
•	0372	gilby	rundle k	
•	0373	gilby	rundle l	
•	0390	golden	slave point a	
•	0393	goose river	primary area	
	0394	goose river	water flood area	
	0395	goose river	beaverhill lake b	
	0413	greencourt	pekisko a	
	0414	greencourt	pekisko c	
•	0421	harmattan east	water flood area	
	0423	harmattan-elkton	rundle b	
•	0425	harmattan-elkton	primary area	
	0426	harmattan-elkton	water flood area	
	0429	haynes	d-3 a	
•	0442	homeglen-rimbey	d-3	
	0505	judy creek south	beaverhill lake	water flood
	0507	judy creek south	beaverhill lake c	
•	0511	kaybob	beaverhill lake b	
•	0526	lanaway	d-3 a	
•	0534	larne	keg river g	
•	0539	larne	keg river l	
	0542	larne	keg river D	
	0619	lone pine creek	d-3 a	
•	0620	loon	slave point a	water flood
•	0624	majeau lake	banff b	
•	0627	malmo	d-3 a	
	0628	malmo	d-3 c	
•	0640	matziwin	pekisko a	
•	0641	matziwin	pekisko b	
•	0677	medicine river	elkton - shunda a	
•	0679	medicine river	elkton-shunda c	
	0680	medicine river	shunda a	
	0681	medicine river	pekisko b	water flood
	0682	medicine river	pekisko c	
	0683	medicine river	pekisko d	
•	0685	medicine river	primary area	
	0686	medicine river	water flood area	
•	0687	medicine river	pekisko f	
•	0690	medicine river	pekisko i	
•	0692	medicine river	pekisko r	
•	0693	medicine river	pekisko s	

Hydrocarbon Miscible, Carbonate Reservoirs (Continued)

0694	meekwap	d-2 a water flood	
0695	mikwan	d-2 a	
0696	mikwan	d-3 a	
• 0713	nevis	d-3 b	
• 0714	nevis	d-3 c	
• 0715	nevis	d-3 d	
• 0716	nevis	d-3 e	
• 0717	nevis	d-3 f	
0732	normandville	mississippian b	
0739	open creek	banff a	
• 0743	paddle river	d-2 a	
0796	pembina	pekisko a	
• 0801	penhold	d-3 a	
• 0804	pouce coupe south	boundary a	
• 0810	princers	pekisko a	
0846	rainbow	keg river w	
• 0855	rainbow	keg river hh	
• 0861	rainbow	keg river nn	
0892	rainbow south	sulphur point b	
0893	rainbow south	muskeg a	
0895	rainbow south	muskeg d	
• 0896	rainbow south	keg river a	water flood
• 0901	rainbow south	keg river f	
• 0902	rainbow south	keg river g	water flood
• 0904	rainbow south	keg river i	
• 0905	rainbow south	keg river j	
0907	rainbow south	keg river l	
0917	red coulee	rundle a	
• 0918	reagan	rundle a	
• 0920	red earth	primary area	
0921	red earth	water flood area	
• 0922	red earth	slave point b	
0923	red earth	slave point c	
0924	red earth	slave point d	
• 0925	red earth	slave point e	
• 0977	senex	keg river a	
• 0978	shekilie	muskeg a	
• 0983	shekilie	keg river e	
• 0985	shekilie	keg river g	
0989	snipe lake	beaverhill lake	water flood
1008	stettler	d-3 a	
1009	stettler	d-3 b	
• 1010	stettler south	d-2	
1011	stettler south	d-3	
1015	sturgeon lake south	d-2 a	
1017	sturgeon lake south	d-3 b	
1019	sundre	primary area	
• 1020	sundre	water flood area	
1022	sundre	primary area	
1023	sundre	water flood area	
1026	swalwell	d-2 a	
1027	swalwell	d-2 b	
• 1029	swan hills	primary area	
1032	swan hills	primary area	
1035	swan hills sruth	primary area	
• 1053	sylvan lake	elkton b	
• 1054	sylvan lake	elkton c	
1055	sylvan lake	elkton e	
• 1056	sylvan lake	elkton f	
• 1058	sylvan lake	pekisko b	
• 1059	sylvan lake	pekisko c	
1061	sylvan lake	pekisko e	
• 1063	sylvan lake	pekisko m	
1064	sylvan lake	d-3 a	
• 1085	tehze	muskeg b	
1086	tehze	muskeg c	
• 1087	tehze	keg river a	
• 1093	turner valley	rundle water flood	
• 1102	turin	lower mannville k	
• 1106	twining north	rundle	
1117	virginia hills	primary area	
• 1125	virgo	muskeg h	
1131	virgo	keg river a	
1133	virgo	keg river c	
• 1136	virgo	keg river f	
• 1142	virgo	keg river i	
1203	virgo	keg river uuu	
1238	virgo	keg river d3d	
• 1242	virgo	keg river h3h	

Hydrocarbon Miscible, Carbonate Reservoirs (Continued)

•	1265	west drumheller	d-3 a
•	1266	westerose	d-3
	1269	westward ho	primary area
	1270	westward ho	water flood area
•	1290	wimborne	d-3 a
•	1302	wood river	d-2 a
•	1304	wood river	d-2 c
•	1305	wood river	d-3 a
•	1321	zama	muskeg b
	1335	zama	muskeg u
•	1340	zama	muskeg aa
	1342	zama	muskeg dd
	1347	zama	muskeg kk
•	1357	zama	keg river ll
•	1410	zama	keg river iii
•	1426	zama	keg river zzz
•	1443	zama	keg river r2r
	1445	zama	keg river t2t
	1454	zama	keg river c3c
	1457	zama	keg river g3g
•	1485	zama	keg river i4i
	1487	zama	keg river k4k
•	1490	zama	keg river n4n
	1491	zama	keg river o4o
•	1492	zama	keg river p4p
	1493	zama	keg river q4q
•	0037	alexander	wabamun b
•	0293	fairydell-bon accord	d-2 a
•	0294	fairydell-bon accord	d-2 b
•	1315	youngstown	arcs
	1369	zama	keg river t